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ENVIRONMENTAL STATEMENT FOR THE PROPOSED PROTOTYPE OIL SHALE LEASING PROGRAM

DES-72-89

Volume II of III

Energy Alternatives

U.S. DEPARTMENT OF THE INTERIOR

SEPTEMBER 1972

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ENVIRONMENTAL STATEMENT

FOR THE

PROPOSED PROTOTYPE OIL-SHALE LEASING PROGRAM

Volume II of III

Energy Alternatives

Prepared in Compliance with

Section 102 (2) (c) of the National Environmental

Policy Act of 1969

Prepared by

UNITED STATES DEPARTMENT OF THE INTERIOR

September 1972

SUMMARY

Draft Environmental Impact Statement
Department of the Interior, Office of the Secretary

1. Type of action: Administrative

2. Brief description of action:

   This proposed action would make available for private development up to six leases of not more than 5,120 acres each. Two tracts are located in each of the states of Colorado, Utah, and Wyoming.

   Such leases would be sold by competitive bonus bidding and would require the payment to the United States of royalty on production. Additional oil shale leasing would not be considered until development under the proposed program had been satisfactorily evaluated.

3. Summary of environmental impact and adverse environmental effects:

   Oil shale development would produce both direct and indirect changes in the environment of the oil shale region in each of the three states where commercial quantities of oil shale resources exist. Many of the environmental changes would be of local significance while others would be of an expanding nature and have cumulative impact. These major regional changes will conflict with other physical resources and uses of the land and water involved. Impacts would include those on the land itself, the water resources and air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation and aesthetic values, and on the existing social and economic patterns as well as others. The environmental impacts from both prototype development and a mature industry are assessed for their anticipated direct, indirect, and cumulative effects.

4. Alternatives considered:

   A. Alternative Leasing Tracts.
   B. Alternative Oil Shale Leasing Policies.
   C. Alternative Energy Policies.
   D. Alternative Energy Sources.

5. Comments have been requested from the following: (see attached sheet).

6. Date made available to CEQ and the public:

   Draft Statement:

Comments Requested

Federal Agencies

Environmental Protection Agency
Department of Commerce
Department of Transportation
Atomic Energy Commission
Federal Power Commission
Office of Emergency Preparedness
Department of Defense - Office of Naval Petroleum and Oil Shale Reserves
Department of Agriculture
Bureau of Sport Fisheries and Wildlife, Department of the Interior
National Park Service, Department of the Interior
Bureau of Recreation, Department of the Interior
Geological Survey, Department of the Interior
Bureau of Mines, Department of the Interior
Office of Coal Research, Department of the Interior
Office of Oil and Gas, Department of the Interior
Bureau of Land Management, Department of the Interior
Bureau of Indian Affairs, Department of the Interior
Bureau of Reclamation, Department of the Interior

State House Agencies

Colorado Department of Local Affairs
Utah State Planning Coordinator
Wyoming State Planning Coordinator
Oil Shale Regional Planning Commission (of Garfield, Mesa and Rio Blanco Counties, Colorado)
County Commissioners of Utah County and Wyoming County

Private Organizations

Natural Resources Defense Council
Rocky Mountain Center on Environment
University of Wisconsin, Glen D. Weaver
Colorado Open Space Council
Sierra Club
Wilderness Society
National Audubon Society
National Recreation and Park Association
Wildlife Management Institute
National Wildlife Federation
Issac Walton League
Environmental Action
Friends of the Earth
Environmental Policy Center
Conservation Foundation
Nature Conservancy
American Forest Association
Center for Law and Social Policy
Environmental Defense Fund
Colorado Sportsmen's Association
Rocky Mountain Sportsmen's Federation
National Council of Public Land Users
Utah Wildlife Federation

Wyoming Open Space Council
American Petrofina of Texas
Ashland Oil, Inc.
Barodynamics, Inc.
Occidental Petroleum Corporation
Garrett Research (Occidental Petroleum Corporation)
Geokinetics, Inc.
Gulf Minerals Resources Company
Marathon Oil Company
The Oil Shale Corporation
Phelps Dodge Corporation
Shell Oil Company
SOHIO Petroleum Company
The Superior Oil Company
Cameron Engineers
Sun Oil Company
Western Oil Shale Corporation
Mobil Oil Company
Chevron Oil Company
Equity Oil Company
Cities Service Oil Company
Carter Oil Company
Union Oil Company
Getty Oil Company
Development Engineering
Denver Audubon Society
Thorn Ecological Institute
Colorado State Rehabilitation Sub-Committee
Denver Research Institute
Humble Oil and Refining Company
AMOCO Production Company
Bell Petroleum Company

INTRODUCTORY NOTE

THIS DRAFT ENVIRONMENTAL STATEMENT HAS BEEN PREPARED PURSUANT TO SECTION 102 (2) (C) OF THE NATIONAL ENVIRONMENTAL POLICY ACT OF 1969 (42 U.S.C. SECS. 4321-4347). ITS GENERAL PURPOSE IS A STUDY OF THE ENVIRONMENTAL IMPACTS OF OIL SHALE DEVELOPMENT.

THE SECRETARY OF THE INTERIOR ANNOUNCED PLANS ON JUNE 29, 1971, FOR THIS PROPOSED PROGRAM AND RELEASED A PRELIMINARY ENVIRONMENTAL STATEMENT, A PROGRAM STATEMENT, AND REPORTS PREPARED BY THE STATES OF COLORADO, UTAH, AND WYOMING ON THE ENVIRONMENTAL COSTS AND PROBLEMS OF OIL SHALE DEVELOPMENT.

THE PROPOSED PROGRAM IS IN CONCERT WITH THE PRESIDENT'S ENERGY MESSAGE OF JUNE 4, 1971, IN WHICH HE REQUESTED THAT THE SECRETARY OF THE INTERIOR INITIATE "A LEASING PROGRAM TO DEVELOP OUR VAST OIL SHALE RESOURCES, PROVIDED THAT ENVIRONMENTAL QUESTIONS CAN BE SATISFACTORILY RESOLVED."

AS PART OF THE PROGRAM, THE DEPARTMENT AUTHORIZED INFORMATIONAL CORE DRILLING AT VARIOUS SITES IN COLORADO AND UTAH AND 16 CORE HOLES WERE COMPLETED. THE DEPARTMENT REQUESTED NOMINATIONS OF PROPOSED LEASING TRACTS ON NOVEMBER 2, 1971, AND A TOTAL OF 20 INDIVIDUAL TRACTS OF OIL SHALE LAND WERE NOMINATED. WITH THE CONCURRENCE OF THE CONCERNED STATES, THE DEPARTMENT OF THE INTERIOR ANNOUNCED ON APRIL 25, 1972, THE SELECTION OF 6 OF THESE TRACTS, 2 EACH IN COLORADO, UTAH, AND WYOMING.

THE PROPOSED PROGRAM IS ESSENTIALLY UNCHANGED FROM THAT ANNOUNCED ON JUNE 29, 1971, BUT THE PRELIMINARY STATEMENT ISSUED AT THAT TIME HAS BEEN EXPANDED TO CONSIDER THE IMPACT OF A FULL-SCALE OIL SHALE INDUSTRY, THE IMPACT OF DEVELOPMENT OF THE SIX SPECIFIC TRACTS, AND A COMPREHENSIVE ANALYSIS OF OTHER ENERGY ALTERNATIVES. THIS INFORMATION IS NOW CONTAINED IN THREE VOLUMES.

THE FIRST VOLUME PROVIDES AN ASSESSMENT OF THE CURRENT STATE OF OIL SHALE TECHNOLOGY. VOLUME I ALSO DESCRIBES THE REGIONAL ENVIRONMENTAL IMPACT OF OIL SHALE DEVELOPMENT IN THE FORM OF PRODUCTION FROM PUBLIC AND PRIVATE LANDS, THE DEVELOPMENT OF WHICH MAY BE STIMULATED BY THE DEPARTMENT'S PROPOSED ACTION. VOLUME II EXTENDS THIS STUDY WITH AN EXAMINATION OF ALTERNATIVES TO SHALE OIL PRODUCTION AT THE RATE OF 1-MILLION BARRELS PER DAY BY 1985. VOLUMES I AND II THUS CONSIDER THE BROAD GENERAL AND CUMULATIVE ASPECTS OF OIL SHALE DEVELOPMENT.

VOLUME III EXAMINES THE SPECIFIC PROPOSED ACTION UNDER CONSIDERATION, WHICH IS THE ISSUANCE OF NOT MORE THAN TWO PROTOTYPE OIL SHALE LEASES IN EACH OF THE THREE STATES OF COLORADO, UTAH, AND WYOMING.

THIS DOCUMENT IS BASED ON MANY SOURCES OF INFORMATION, INCLUDING RESEARCH DATA AND PILOT PROGRAMS DEVELOPED BY BOTH THE GOVERNMENT AND PRIVATE INDUSTRY OVER THE PAST THIRTY YEARS. MANY FACTORS SUCH AS CHANGING TECHNOLOGY, EVENTUAL OIL PRODUCTION LEVELS, AND

ATTENDANT REGIONAL POPULATION INCREASES ARE NOT PRECISELY PREDICTABLE. THE IMPACT ANALYSIS INCLUDED HEREIN IS CONSIDERED TO CONSTITUTE A REASONABLE TREATMENT OF THE POTENTIAL ENVIRONMENTAL EFFECTS WHICH WOULD BE ASSOCIATED WITH OIL SHALE DEVELOPMENT. DEPARTMENTAL EXPERTS, IN THE MANY AREAS WHICH ARE DISCUSSED, HAVE USED THEIR BEST JUDGMENT TO FORECAST THESE ENVIRONMENTAL EFFECTS.

ANY WRITTEN COMMENTS ON THIS DRAFT STATEMENT RECEIVED WITHIN 45 DAYS OF THE ISSUANCE OF THIS STATEMENT WILL BE GIVEN CAREFUL CONSIDERATION. PUBLIC HEARINGS WILL BE SCHEDULED WITHIN THE SAME 45-DAY REVIEW PERIOD. UPON COMPLETION OF THE REVIEW PERIOD, THE DEPARTMENT WILL WEIGH ALL INFORMATION AND COMMENTS RECEIVED AND, IF THE DECISION IS TO PROCEED FURTHER, WILL PREPARE A FINAL ENVIRONMENTAL STATEMENT. ONLY AFTER COMPLETION OF THE FINAL ENVIRONMENTAL STATEMENT AND COMPLIANCE WITH ALL THE REQUIREMENTS OF NEPA AND THE COUNCIL ON ENVIRONMENTAL QUALITY GUIDLINES ISSUED PURSUANT TO IT, WILL A FINAL DECISION BE MADE WHETHER TO PROCEED WITH AN OIL SHALE LEASING PROGRAM.

AVAILABILITY OF DRAFT ENVIRONMENTAL STATEMENT

The three-volume set may be purchased by mail or in person from the Map Information Office, Geological Survey, U. S. Department of the Interior, Washington, D. C. 20240. The set is priced at $7.00. Individual volumes are $3.00 for Volume I, $1.00 for Volume II, and $3.00 for Volume III.

Copies may also be purchased from Bureau of Land Management State Offices in the following cities: Denver, Colo. (Colorado State Bank Building, 1600 Broadway, Denver, Colorado, 80202); Salt Lake City, Utah (Federal Building, 124 South State, Salt Lake City, Utah, 84111); and Cheyenne, Wyo. (Joseph C. O'Mahoney, Federal Center, 2120 Capital Avenue, Cheyenne, Wyoming, 82001). Inspection copies are available in the following Bureau of Land Management district offices: Colorado: Canon City, Craig, Glenwood Springs, Grand Junction, Montrose; Utah: Vernal, Price, Monticello, Kanab, Richfield; Wyoming: Rock Springs, Rawlins, Casper, Lander, Pinedale, Worland.

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I. INTRODUCTION

In his clean energy message to the Nation, President Nixon, on June 4, 1971, emphasized that the United States is now entering a period of increasing demand for energy and growing problems of supply. As an element of the President's comprehensive energy program to help assure future energy supplies, Interior Secretary Morton outlined a concept for a Proposed Prototype Oil-Shale Leasing Program (1).[1/] The goal of the Department of the Interior's proposed prototype leasing program is "to provide a new source of energy for the Nation by stimulating the timely development of commercial oil-shale technology by private enterprise, and to do so in a manner that will assure the minimum possible impact on the present environment while providing for the future restoration of the immediate and surrounding area " (2).

This section of the environmental impact statement discusses energy alternatives to the proposed action cast in the framework of the Proposed Prototype Oil-Shale Leasing Program (2). This prototype plan anticipates six test leases, two each in the States of Colorado, Utah, and Wyoming, and a program that might lead to a maximum total production of 1 million barrels of shale oil per day by the year 1985 from both public and private lands. The results of prototype development would provide the background information needed to formulate more comprehensive resource utilization programs and required land use plans. It will also provide the detailed information needed to assess the actual environmental impact

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1/ Underlined numbers in parentheses refer to items in the list of references at the end of this section.

caused by oil-shale development. If and when general leasing of public lands is proposed, another Environmental Impact Statement will be prepared.

This document, which considers alternatives to the Proposed Prototype Oil-Shale Leasing Program, is organized in the following way. The initial part of the report considers the energy situation, the role of energy in economic growth, and the energy requirements of the U.S. to meet projected future needs. To relate the Proposed Prototype Oil-Shale Leasing Program to the total energy picture, the subject of substitutability of energy forms is discussed which is followed by a consideration of factors that affect fuels development. A background of the petroleum situation, both present and future, is presented followed by an outline of oil-shale development possibilities. Finally, alternatives to the Proposed Prototype Oil-Shale Leasing Program are discussed. These alternatives exist in two broad general categories: (1) Those that arise from Federal policy actions regarding petroleum and natural gas and (2), those that arise from substituting other energy forms for the shale oil that would be produced. The environmental impacts of each reasonably available and technologically feasible alternative are discussed.

A. References Cited

1. Secretary Morton's Departmental Energy Statement to the Senate Committee on Interior and Insular Affairs, dated June 15, 1971.

2. Program Statement for the Proposed Prototype Oil-Shale Leasing Program. U.S. Department of the Interior, June 1971.

II. THE ENERGY SITUATION

A. The Role of Energy in Economic Growth

Abundant supplies of low-cost energy supported economic growth throughout the history of the United States. Water power was important for early industries in New England; coal was important for railroads and industries through the early part of this century; and petroleum has supplied much of the energy during the automobile and jet age.

The close correlation between energy consumption and gross national product is shown in figure 1. The latest report of the Council of Economic Advisers discusses relationships between the GNP and energy consumption as follows:

> "The growth in consumption of fuels by automobiles, electric generating plants, homes, and factories is closely associated with increases in our material levels of living. Historically, however, energy use has not grown as rapidly as GNP. While real GNP (in 1958 dollars) rose from $183.5 billion in 1930 to $617.8 billion in 1965, for a compound annual growth of 3.5 percent, energy consumption rose from 22.3 quadrillion btu's to 54.0 quadrillion btu's during the same period, an annual growth rate of only 2.5 percent. The use of energy per dollar of GNP (figure 2), therefore, fell from 121,500 btu's in 1930 to 87,400 in 1965.

> "During this same period, energy was becoming cheaper relative to other goods and services. While the price index of all goods and services (the GNP deflator) rose 125 percent during this period, the wholesale price index of fuels and electric power rose only 70 percent. Thus, although energy consumption was growing it was not growing as rapidly as GNP, and although energy prices were rising they were not rising as fast as the prices of other goods and services.

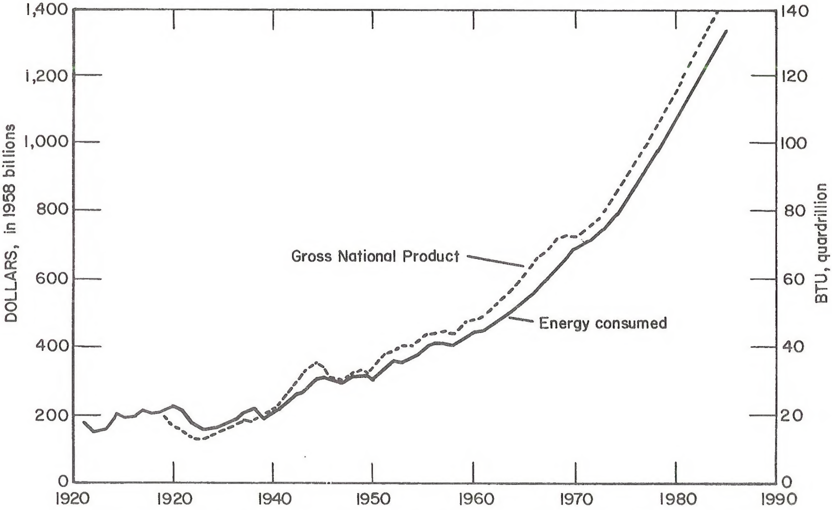

Figure 1. – Energy Consumption and Gross National Product, 1920–1970, with Projections to 1990.

Source: Office of Oil and Gas, Department of the Interior, May 1971.

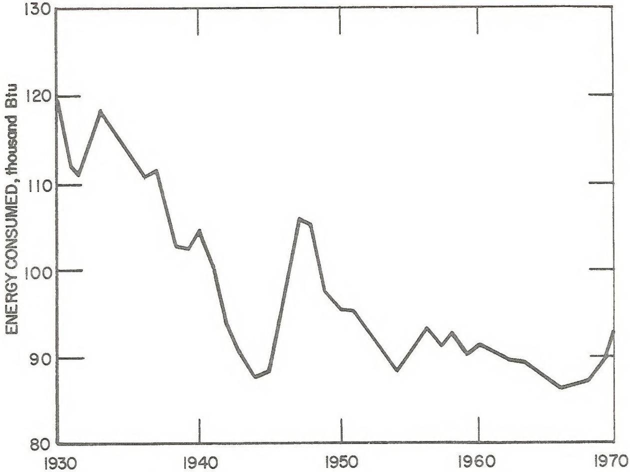

Figure 2. – Energy Consumed in the United States per Dollar of GNP*, 1930–1970 in 1958 Dollars. Source: Statistical Abstract of U.S. (GNP), Bureau of Mines (Energy)

Source: Statistical Abstract of U.S. (GNP)
Bureau of Mines (Energy)
Source: Reference (6, pg. 2)

"Since 1965, however, a sharp upturn in the energy-GNP ratio has occurred. From 87,400 btu's per dollar of real GNP in 1965, the number rose to 95,600 in 1970. While output for the economy as a whole was growing at 3.1 percent per year, energy consumption grew at 5.0 percent. This sharp upturn in energy was associated with a more rapid increase in prices. Prices of fuel oil and bituminous coal, in particular, rose sharply in 1970.

"These developments gave evidence of at least a short-run shift in energy demand and prices. At the same time more fundamental changes were occurring in the domestic supply picture... discussed in detail below ...

"The accelerated growth in energy demand relative to GNP in recent years is not expected to continue. Most observers forecast an annual average growth in energy consumption of just over 4 percent, paralleling the expected growth in GNP. A comparison of earlier forecasts and current realities, however, suggests that any assumptions about future demand and supply must be regarded as tentative, to be modified as new evidence becomes available" (1).

An analysis (2) of the possible reasons for the reversal of the trend in the energy consumption-gross national product relationship found no single cause, but suggested that the trend reversal was due principally to a combination of three causes: "(a) the increasing relative importance of nonenergy uses of fuels, (b) tapering-off in the year-to-year improvement in thermal efficiency at central power stations, and (c) the increasing relative importance of air conditioning and electric heating." That study also found that the reversal was probably not due to the increasing importance of the service sector in the computation of gross national product. Another source (3) attributes most of the change to the substitution of "electricity, with a thermal efficiency of perhaps 32 percent, for many direct fuel uses with efficiencies ranging from 60 to 90 percent." From

these relationships, it is clear that, unless our energy-based society changes quite markedly, maintenance and improvement of the material standard of living will continue to demand a commensurate increase in energy.

The United States, which has 6 percent of the world's population, uses 35 percent of the energy consumed each year (4). Because energy consumption in other countries is similarly correlated with both economic growth and population, figure 3, world energy consumption may be expected to rise much faster than domestic consumption, as world population is growing rapidly and the economic growth of the less developed countries is rising rapidly. For the world as a whole, per capita energy consumption is rising about a third faster than per capita consumption in the U.S. (5) (figure 4). As a result, the U.S. share of world consumption is expected to fall to 25 percent by the year 2000 (6), but total requirements for energy will increase.

B. Energy Requirements (6)

Forecasts of demand for energy resources to the year 2000 have been projected by the Bureau of Mines. These forecasts were developed from an energy model of the U.S. that correlated resource inputs and endwise market demands with broad economic indicators such as GNP, population projections, and industrial production. As a result of these studies, a conventional or base forecast was made having the following conditional assumptions: GNP was assumed to grow at an annual rate of 4 percent;

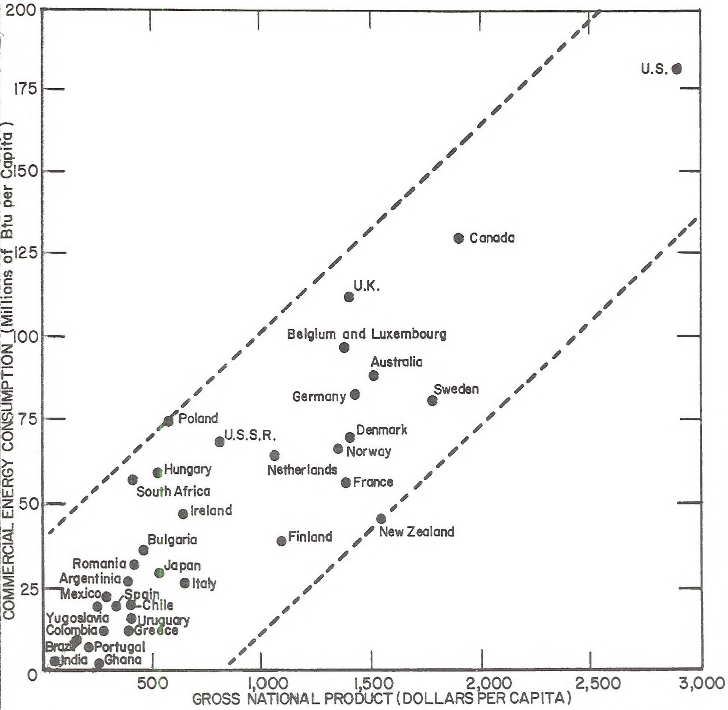

Figure 3 .-Relation of Per-Capita Energy Consumption and Gross National Product, Worldwide

Dotted lines, drawn parallel to U.S. rate and enclosing all data points, added for this figure.
Source: Reference (3, pg. 142)

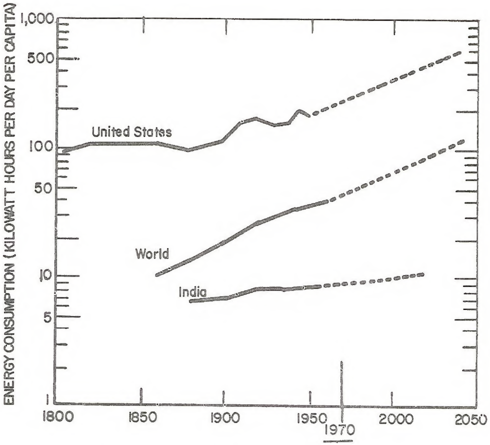

Figure 4. – Trends in Per-Capita Energy Consumption.
(Note logarithmic scale)

Source: Reference (4, pg. 40)

industrial production was based on a composite growth rate of 4.4 percent; foreign trade in energy was assumed to remain at the same relative proportions as in the past; and evolutionary changes in technologies and efficiencies were presumed. In addition, it was assumed that the real costs of energy will increase at a relatively steady rate, but prices for specific fuels and energy forms will vary according to availability of supplies, environmental requirements, and technological development.

Table 1 presents preliminary data on U.S. demand for energy resources in 1970 and the current forecast of demand for energy resources, by major sources, in the near term (1975), the intermediate term (1985), and the long term (2000). The indicated demand levels are a summation of the current best estimates by the Bureau of Mines of probable demands for individual resources. The forecast indicates a total gross energy input of 192 quadrillion btu's in the year 2000 representing a compound annual growth rate of 3.5 percent for the 30-year period from 1970 to 2000.

Per capita consumption of energy has increased rapidly in recent years. This demand forecast reflects this increased consumption per consumer as well as the growing number of consumers. The following tabulation demonstrates this trend in total energy consumption per capita.

TABLE 1. - United States demand for energy resources by major sources, year 1970 and estimated probable demand in 1975, 1985, and 2000[1/]

	1960[2/]	1970[2/]	1971[1/]	1975	1985	2000
Petroleum (includes natural gas liquids)[3/]						
Million barrels	3,611	5,365	5,523	6,550	8,600	12,000
Million barrels per day	9.89	14.70	15.13	17.9	23.56	32.79
Trillion Btu	20,067	29,614	30,492	36,145	47,455	66,216
Percent of gross energy inputs	45.0	43.9	44.2	40.8	35.6	34.6
Natural gas (includes gaseous fuels)						
Billion cubic feet	12,269	21,367	22,050	27,800	38,200	49,000
Trillion Btu	12,699	22,029	22,734	28,690	39,422	50,568
Percent of gross energy inputs	28.5	32.7	33.0	32.4	29.5	26.4
Coal (bituminous, anthracite, lignite)						
Thousand short tons	398,029	525,406	510,750	615,000	850,000	1,000,000
Trillion Btu	10,140	12,922	12,560	16,106	22,260	26,188
Percent of gross energy inputs	22.8	19.2	18.2	18.2	16.7	13.7
Hydropower, utility[4/]						
Billion kilowatt hours	154	249	267	282	363	632
Trillion Btu	1,657	2,616	2,798	2,820	3,448	5,056
Percent of gross energy inputs	3.7	3.9	4.1	3.2	2.6	2.6
Nuclear power[5/]						
Billion kilowatt hours	5.6	21.8	36.7	462	1,982	5,441
Trillion Btu	6	229	391	4,851	20,811	43,528
Percent of gross energy inputs	neg.	0.3	0.5	5.4	15.6	22.7
Total gross energy inputs, trillion Btu	44,569	67,410	68,975	88,612	133,396	191,556

1/ Preliminary estimates by Bureau of Mines staff.
2/ Actually consumed in 1960 and in 1970.
3/ Product demand - includes net processing gain.
4/ Includes pumped storage, internal combustion and gas turbine generation. Converted at prevailing and projected central electric stations average heat rates as follows: 10,494 Btu/Kwhr in 1970 and 1971; 10,000 Btu in 1975; 9,500 in 1985; and 8,000 in 2000.
5/ Converted at average heat rates of 10,494 Btu/Kwhr in 1970; 10,660 in 1971; 10,500 in 1975 and 1985; and 8,000 in 2000.

Source: U.S. Department of the Interior, U.S. Energy: A Summary Review, 1972. Table revised 2/22/72.

Year	Population (millions)[1/]	Total energy consumption (trillion btu)	Per capita consumption (million btu)
1950	152	34,154	225
1960	180	44,960	250
1970	204	68,810	337
1975	215	88,612	412
1985	237	133,396	563
2000	266	191,556	720

1/ The population projections are based on latest Bureau of Census data, pp. 25-448 of 8/6/70, Series E; the lowest rate of projected population growth.

As stated earlier, the future energy requirements are based upon a variety of forecasting techniques and the personal judgment of experts, especially with respect to the timing of possible technological developments. Gross national product, population, manufacturing indices, and other basic economic data were correlated with energy consumption and any important and consistent trends were extrapolated. However, science and technology can and probably will produce some revolutionary as well as evolutionary technological, environmental, and economic changes that could significantly alter energy supply and demand patterns. Such developments cannot be forecast with reasonable assurance; therefore, only evolutionary developments considered as logical outgrowths of present trends and efforts were used. Accordingly, the energy demands forecast should be considered as order of magnitude levels to provide planning targets and not as absolute commodity demand predictions.

In coming years some energy commodities, notably natural gas, will encounter supply limitations; others will be disqualified from some markets by environmental restrictions. To the extent that these limiting factors

materialize, requirements will have to be filled by other energy commodities. Petroleum demand is especially difficult to project. For example, the Bureau of Mines staff forecast, presented in table 1 and used as the basis for subsequent analyses in this report, anticipates a petroleum demand of 23.56 million barrels a day by 1985, whereas other current projections, less optimistic with regard to useable supplies of other fuels, see oil demand rising above 26 million barrels a day in that year (7).

C. Substitutability of Energy Forms

The use of energy materials can generally be considered in terms of the physical state of the energy source--i.e., solid, liquid, or gas. Thus, though some substitutability is possible, the most likely substitute for a liquid energy source material will be another liquid energy source material within a 10- to 15-year time frame. The reason is obvious. For example, liquid petroleum fuels are the most widely used materials for the automobile and these vehicles have a life of about 12 years. Unless technological advancement gives energy converters that will use other forms of fuel, transportation needs will be dependent upon liquid energy sources from petroleum or some other substitute that can be converted to a liquid form (i.e., coal liquefaction or oil shale).

Mineral Facts and Problems presents the following discussion of the potential for alternatives to petroleum (8):

> "...Petroleum currently has a virtual monopoly in the fields of transportation, organic chemicals, lubes, and waxes. The substitution of other materials for petroleum would not be economically feasible in most uses because of the higher cost of raw materials and the cost of equipment conversion.
>
> "Gasoline has no successful competitor as a passenger car fuel; however, steam and electric prime movers, which were utilized but discarded many years ago, are again undergoing experimentation. The use of natural gas (compressed or liquefied) also is being investigated. [But the supply situation in gas appears to be more severe than that in oil.] The use of electricity as motive power in utility vehicles such as golf carts is increasing.
>
> "For some commercial vehicles, trucks and tractors there is competition between gasoline, diesel oil, and LPG. Diesel engines are used to a limited extent in automobiles. Diesel locomotives have performed so well for U.S. railroads that the majority of the roads have converted to diesels from coal. In aviation, jet

fuel is replacing gasoline. Liquefied natural gas and other fuels are possible substitutes for petroleum jet fuels in supersonic aircraft. [However, such substitution does not alleviate the liquid fuel problem.]

"In household, commercial, and industrial heating, and in the generation of steam and [electrical] power, distillate and residual fuels compete with coal and natural gas. A competitor with growing strength in the household heating market is electricity, which is generated from several fuel sources including fuel oil. In industrial and large commercial applications, price frequently is more decisive than it is in domestic or small commercial uses where convenience and related factors outweigh the price advantages of other fuels.

"Air quality regulations is a factor of increasing importance in fuel substitution. Alternative energy sources are being discussed as possible substitutes for air-polluting petroleum fuels in some uses. Such sources include electricity, natural gas, and nuclear energy." [The conversion of liquid or gaseous fuel to electrical energy is a consumer of energy because of the inefficiency of the current conversion techniques. Therefore, any increase in electrical generation has the potential for increasing the demand for liquid fuels.]

Significant conversion of energy consumption from one form to another is not likely in the time frame of the projected development of oil shale under the prototype oil-shale leasing program. This document, therefore, is organized to consider shale oil in its most likely energy use form--as a supplement for the use of petroleum liquids.

Other energy forms can be substituted only partially for crude oil. Over half the demand for such oil is for transportation use, for which satisfactory large-scale alternatives to liquid fuels are unlikely during the 1980-1985 period. The most commonly suggested alternative is to replace residual oil as a fuel for electric utility boilers by some other fossil fuel or some other form of electricity generation. Several of the alternatives considered would require such substitution. However, use of petroleum for electricity generation in 1970 was less than 1 million barrels

per day and projected use for this purposed in 1980 is some 2 million barrels per day. Thus, substitution of this nature essentially would require removing an entire sector of petroleum usage, and at a time when low sulfur residual oil is being substituted for coal to generate electricity.

It must be kept in mind, however, that all forms of energy supplement one another in the total energy picture. Thus, if the use of one kind of energy source material is freed from use in electrical power generation, for example, the material freed is available for use elsewhere in the total energy picture, but other forces are set in motion that require adjustment of materials usage throughout the entire energy picture--the total energy demand will remain the same.

D. Fuels Development and the Environment

The environmental impact caused by fuels development will vary significantly, depending on the energy form to be utilized. A review of the present situation has been prepared by Mills, Perry, and Johnson (9). Their review is outlined in Table 2; pertinent sections of the text of that review are quoted below:

TABLE 2. Significant Environmental Impacts; Fuels Development

	Impacts on Land Resource			Impacts on Water Resource			Impacts on Air Resource		
Energy Source	Production	Processing	Utilization	Production	Processing	Utilization	Production	Processing	Utilization
Coal	Disturbed Land	Solid Wastes	Ash, slag disposal	Acid Mine Drainage		Increased Water Temp.'s			Sulfur oxides Nitrogen oxides Particulate Matter
Uranium	Disturbed Land		Disposal of radioactive material		Disposal of radio-active material	Increased Water Temp.'s			
Oil				Oil Spills, Transfer, Brines		Increased Water Temp.'s			Carbon monoxide Nitrogen oxides Hydrocarbons
Natural Gas						Increased Water Temp.'s			
Hydro									

Source: Reference (9, pg. 31)

"Land use

"About 3.6 billion tons of solid wastes are generated each year in the U.S. Agricultural wastes constitute nearly two-thirds of the total, and mineral wastes account for most of the rest....fuels account for only 125 million tons, or about 3% of all solid wastes generated.

"The last complete survey of mining operations in the U.S. indicated that, in 1965, about 3.2 million acres of land had been disturbed by surface mining. Of this total, about 41% resulted from activities associated with coal production.

"As yet, only a few tenths of 1% of the total land area of the U.S. has been disturbed by surface mining. Effects of such mining upon the environment, however, vary widely and depend upon such factors as the type of mining, characteristics of overburden, steepness of the terrain, amount of precipitation, and temperature. Where land reclamation is not practiced, water pollution from acid mine drainage and silt damage occur...In the principal coal mining areas, the average costs of completely reclaiming coal lands range from $169 to $362 per acre, an average cost of 4 to 8 cents per ton.

"Underground coal mining can cause subsidence unless the mining systems are designed to prevent deterioration and failure of abandoned mine pillars. Underground fires may weaken or destroy coal pillars that support the surface, causing subsidence with consequent damage to surface structures. An additional threat is the possible collapse of buildings and openings of surface fissures and potholes.

"Fuel processing also contributes large quantities of wastes during the washing of coal to improve its quality. Over 62% of all coal mined is washed, producing 90 million tons of waste annually. If not returned to the mine, the water accumulates in piles near the plant and mine. At times, these piles ignite and burn for long periods, thus creating air pollution. Rainwater leaches salts and acid from the piles to contaminate nearby streams.

"Utilization of coal also produces solid waste in the form of ash and slag. About 30 million tons of these materials are collected each year; an estimated 8 million tons are discharged into the atmosphere.

"Uranium mined by either open pit or underground methods creates similar land problems. However, since uranium mining in quantity is a relatively new industry, the volumes and tonnages involved are only 1% of those for coal, and the adverse effects are much smaller....

"Solid wastes resulting from nuclear generation of electricity involve only small tonnages of materials, but have a very great potential for environmental damage for long periods because of their radioactivity.....

"<u>Water problems</u>

"Two distinct water problems are of growing concern in fuels management--water quality and water temperature. Questions of quality relate to individual energy sources; thermal problems, however, are common to use of all fuel commodities.

"Poor water quality, whether it be through chemical pollution or sedimentation, is a major damage resulting from both surface and underground mining. Available data make no distribution between the two, but it has been estimated that approximately 48% of mine water pollution, primarily sediment, results from surface mining. In the U.S., some 5800 miles of streams and 29,000 surface acres of impoundments and reservoirs are seriously affected by such operations. Acid drainage from underground mines is more difficult to control than that from surface mines, but preventing water from entering the mine and the rapid removal of water which does get into the mine are effective methods for reducing pollution... Erosion and sedimentation from surface mining are serious problems in many areas, but they can be prevented by controlling the surface runoff that follows rainstorms.

"In processing uranium ores, some of the potentially hazardous radioactive elements or isotopes, particularly Ra-226 and Th-230, are partly dissolved during the leaching operation used to recover uranium oxide. While most processing plants are located in very isolated areas, steps are taken to avoid pollution of water supplies by radioactive constituents of liquid effluents.

"Disposal of the effluent is accomplished principally by impoundment and evaporation, controlled seepage into the ground, and injection through deep wells into saline or nonpotable aquifers. Where ore processing plants are adjacent to rivers or streams, the effluents may be released directly to the streams at controlled rates if, after dilution, the concentration is within predetermined limits. During periods of low stream flow, effluents are impounded or may be chemically treated before release.

"Onshore oil production, except for accidental occurrences, does not present any difficult pollution problem. Nevertheless, nearly three barrels of brine must be disposed of for every barrel of oil produced. Accidental pollution may occur from blowouts of wells, dumping of oil-based drilling muds, or losses of oil in production, storage, or transportation. At sea, the blowout at Santa Barbara, the oil slicks and the fires and oil spills in the Gulf of Mexico in recent months have demonstrated that these dangers are more than academic in offshore operations. Methods must be found for their prevention and control. Spills and discharges from tankers are also important. However, the greatest, if less dramatic, problem is the contamination of inland waterways and harbors resulting from transfer of oil between or from vessels.

"Thermal pollution

"By far the most important water problem resulting from fuel use is thermal pollution. Over 80% of all thermal pollution arises from the generation of electricity. The amount of heat rejected to cooling water represents 45% of the heating value of the fuel used in the most efficient fossil fuel plants, and 55% in nuclear plants. If projected use of electricity is accurate and if nuclear energy, as expected, supplies nearly 50% of the electricity demand, more than 10 times as much heat will be rejected to turbine cooling water in 2000 as is being rejected now. Even with greatly increased use of brines or seawater for cooling, the demands for fresh cooling water will be larger than its supply.

"Air pollution

"Nearly 80% of all air pollution in the U.S. is caused by fuel combustion. About 95% of all sulfur oxides, 85% of all nitrogen oxides, and over half of the carbon monoxide, hydrocarbons, and particulate matter are produced by fuel use. Management of fuels, therefore, is critical for the minimization of the nation's air pollution problems.

"The most competitive market for fuels is the generation of electricity. Not only do the fossil fuels compete with each other, but they also compete with hydropower and, more recently, with nuclear energy. Obviously, from an air pollution standpoint, hydropower is the perfect method of electricity generation. During the generation of electricity from fossil fuels, production of oxides of nitrogen or carbon monoxide is not greatly different for any of the fossil fuels used. The production of electricity using natural gas produces no sulfur oxide emissions, but the use of coal and residual oil in electric generating plants is the source of 74% of all the oxides of sulfur emitted into the air.

"About seven times as much coal as oil is used in electricity generating plants. For this reason, and because of its relatively high sulfur content, coal accounts for nearly two-thirds of the sulfur oxides emitted to the atmosphere. In addition, nearly one-third of the particulate matter emitted into the atmosphere is from burning coal for generation of electricity.

"About one-half of the coal consumed by industry is used to make coke. . . .

"Local air pollution problems in the vicinity of plants that make coke are severe. Alternatives to the use of coke for the production of pig iron are available, and these processes might reduce the amount of air pollutants released to the air. Uncontrolled surface and underground coal fires emit smoke, fumes, and noxious gases.

"About 17% of all the oil consumed in this country is used by industry. Much of it is residual oil, which in most cases is high in sulfur. Moreover, residual oil is difficult to burn efficiently and is usually burned in large equipment at high temperatures. Because of these two factors, industrial use of oil tends to contribute larger amounts of carbon monoxide, hydrocarbons, and oxides of nitrogen than the household and commercial sector, which consume about 25% of the fuel oil.

"The largest use of oil is for gasoline to power the nation's 100 million vehicles. About 42% of each barrel of oil is used in this manner. If we include diesel and jet fuels, about 54% of each barrel of oil is used for transportation.

The use of fuels in transportation causes approximately one-half of all the air pollution in the U.S. There are alternatives to the use of gasoline for automobiles and trucks, such as natural gas and liquefied petroleum gases. But it is doubtful that the massive changeover that would be required by two of the country's largest industries would occur if other solutions could be found to reduce air pollution generated by the transportation sector."

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III. PETROLEUM

In 1970 the United States consumed petroleum products at an average rate of 14.7 million barrels a day. Petroleum comprised 44 percent of our national energy supply, including almost all of our transportation fuel, 45 percent of energy used in households and commercial establishments, almost a quarter of our industrial energy, and 13 percent of the energy input of electric power stations.

Precise estimates of future petroleum requirements are difficult. Recent projections of the demand growth rate to 1975 vary from 3.2 percent to 5.0 percent. Department of the Interior's projections of demand approximate 18.0 million barrels a day in 1975 and anticipate an annual growth rate between 4.0 percent and 4.7 percent. Beyond 1975 projection becomes increasingly difficult.

Variables which complicate near term projections include rates of economic growth, an apparent shift toward increased energy consumption relative to real gross national product, and potentials for sizeable shifts to petroleum from other fuels as energy users seek to meet new environmental standards and as they encounter limitations in supplies of natural gas. In the longer term, other important unknowns must be considered such as; technological advances in nuclear energy, and the use of coal in the production of synthetic oil and gas; Federal regulatory policies as they relate to oil and natural gas; and changes in cost relationships and life styles which may appreciably affect energy requirements. The latter include possible major shifts in transportation

patterns, such as greater dependence on mass transit and a possible trend toward smaller and more efficient autos, and potentially a shift from internal combustion engines in motor vehicles in the interest of environmental quality improvement.

Within the probable range of future U.S. oil requirements, one conclusion seems obvious. Even with a major increase in domestic petroleum finding and producing efforts, the United States will become increasingly dependent on other nations for oil supplies. Ultimately, production of synthetic oil from shale, coal, or tar sands may contribute to domestic self-sufficiency; but before these sources can begin to make significant contributions, we may become dependent on foreign sources for as much as half of our petroleum supplies. This estimate of dependence assumes that we will be able to maintain domestic petroleum production near its present level. Some industry analysts have questioned our ability to sustain these rates. The less optimistic anticipate a decline of about 30 percent in production from 1970 to 1985.

An estimated 2.8 trillion barrels of crude petroleum and more than 200 billion barrels of natural gas liquids occurred originally in place in the earth within the United States and its offshore areas. About half of these resources are offshore, and of this portion, about half are in water depths greater than 200 meters. However, only 171 billion barrels of petroleum offshore and 246 billion onshore are estimated to be recoverable under current technological and economic conditions--once they have been found. (See Fig. 5.) Proved reserves of crude petroleum and

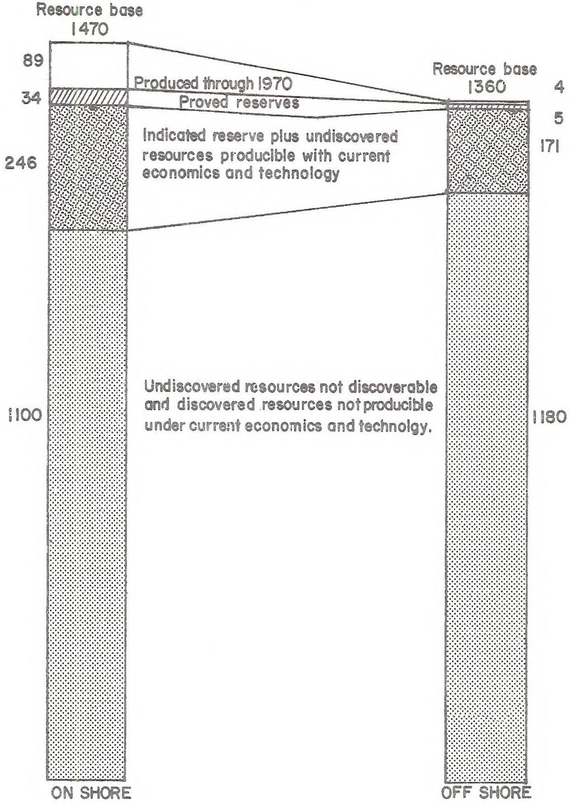

Figure 5 .— U.S. Crude Oil Resources (Billion barrels)

Source: Reference (10, pg. 16)

of natural gas liquids, both on and offshore, amount to 39 billion and 7.7 billion barrels, respectively. Included are 9.6 billion barrels of crude petroleum reserves on Alaska's North Slope. Reserves in the lower 48 States declined in recent years. About 4 billion barrels of petroleum liquids were produced in the United States in 1971. The ratio of reserves to production in the Lower 48 States has fallen to about 8.8 for crude oil.

A. Components of Demand for Petroleum

Table 3 shows petroleum consumption by major products and by major consuming sectors in 1968. The following discussion of current consumption patterns in that year is taken from Bureau of Mines 1970 Mineral Facts and Problems (1):

"About 90 percent of the petroleum products consumed in the United States in 1968 were used to produce energy in the form of heat and power. Such products included motor and aviation gasolines, distillate fuels, residual fuels, liquefied petroleum gases, jet fuels, kerosine, and petroleum coke. The remaining 10 percent consisted of products used for nonenergy purposes and included petrochemical feedstocks, asphalt, road oil, solvents, coke, lubricants, waxes, and miscellaneous products.

"The 1968 demand for petroleum products by major consuming sectors is shown in... [table 3]...A breakdown of product demand on a percentage basis by energy and nonenergy uses is shown in [table 4]...

"Approximately 66 percent of the nonenergy products was consumed in the industrial sector for making petrochemicals, in aluminum manufacturing, as lubricants and waxes, and for other purposes; 29 percent was used in the commercial sector in the form of asphalt and road oil; and 5 percent was consumed as lubricants in the transportation sector.

Table 3.

Petroleum consumption by major products and by major consuming sectors[1] in 1968[p]

	Household and commercial		Industrial		Transportation[2]		Electricity generation, utilities		Miscellaneous and unaccounted for		Total domestic products demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
Fuel and power:												
Liquefied gases	171.1	686.3	20.8	83.4	30.0	120.3	...	...	3.4	13.7	225.3	903.7
Jet fuel (kerosine and naphtha types)	...	...	...	...	348.3	1,938.0	...	...	...	...	348.3	1,938.0
Gasoline	...	...	...	...	1,955.8	10,264.8	...	...	...	...	1,955.8	10,264.8
Kerosine	78.7	446.2	23.5	133.2	...	...	...	...	.9	5.1	103.1	584.5
Distillate fuel	555.0	3,232.8	61.3	357.1	212.9	1,240.1	3.0	17.5	30.5	177.7	862.7	5,025.2
Residual fuel	196.0	1,232.3	171.0	1,075.0	127.9	804.1	185.0	1,163.1	...	...	679.9	4,274.5
Still gas	...	...	149.8	898.8	...	...	...	...	...	...	149.8	898.8
Petroleum coke	...	...	54.2	326.5	...	...	...	...	...	...	54.2	326.5
Total	1,000.8	5,597.6	480.6	2,874.0	2,674.9	14,367.3	188.0	1,180.6	34.8	196.5	4,379.1	24,216.0
Raw material:[3]												
Special naphthas	...	...	27.0	141.7	...	...	...	...	...	...	27.0	141.7
Lubes[4] and waxes	...	...	28.5	170.5	24.1	146.2	...	...	...	...	52.6	316.7
Petroleum coke	...	...	22.1	133.2	...	...	...	...	...	...	22.1	133.2
Asphalt and road oil	148.2	983.5	...	...	...	...	...	...	...	...	148.2	983.5
Petrochemical feedstock offtake:												
Liquefied refinery gas	...	...	46.5	186.5	...	...	...	...	...	...	46.5	186.5
Liquefied petroleum gas[5]	...	...	113.9	456.9	...	...	...	...	...	...	113.9	456.9
Naphtha (−400°)	...	...	55.6	291.8	...	...	...	...	...	...	55.6	291.8
Still gas	...	...	9.8	58.8	...	...	...	...	...	...	9.8	58.8
Miscellaneous (+400°)	...	...	27.5	160.2	...	...	...	...	...	...	27.5	160.2
Total	148.2	983.5	330.9	1,599.6	24.1	146.2	...	...	...	...	503.2	2,729.3
Miscellaneous and unaccounted for	...	...	...	...	...	...	...	...	17.9	98.8	17.9	98.8
Total domestic product demand	1,149.0	6,581.1	811.5	4,473.6	2,699.0	14,513.5	188.0	1,180.6	52.7	295.3	4,900.2	27,044.1

[p] Preliminary.
[1] Includes liquefied refinery gas and natural gas liquids.
[2] Includes bunkers and military transportation.
[3] Includes some fuel and power use by raw material industries.
[4] Lubricants are distributed equally between the Industrial and Transportation sectors.
[5] Includes LP gas for synthetic rubber.

Source: Reference (1, pg. 158)

Table 4.

Sector	Percent 1967	Percent 1968
Energy uses (fuel):		
Household and commercial	20.5	20.4
Industrial	10.8	9.8
Transportation	54.5	54.6
Electricity generation utilities	3.5	3.8
Not specified	.7	.7
Nonenergy uses:		
Petrochemical feedstocks	5.1	5.2
Other	4.6	5.1
Miscellaneous and unaccounted for	.3	.4
Total	100.0	100.0

Source: Reference (1, Pg. 160)

Table 5.

Product	Growth rate, 1964 to 1968, inclusive (percent)
Liquefied gases (fuel use)	6.5
Jet fuel	12.7
Gasoline	3.9
Motor	4.3
Aviation	−9.5
Kerosine	1.9
Distillate fuel	2.9
Residual fuel	4.8
Still gas (fuel use)	3.0
Petroleum coke	1.9
Special naphthas	3.6
Lubricants and waxes	2.1
Asphalt and road oil	3.6
Petrochemical feedstocks	10.2
Miscellaneous and unaccounted for	1.8
Total product demand	4.5

"To facilitate discussion of uses, the trends in product consumption are indicated in [table 5],...which includes annual compound growth rates for the major products used during the 5-year period ending with 1968.

"Gasoline and diesel oil (distillate) are consumed primarily as fuel in mobile and stationary engines. By far the largest use is for transportation purposes, including automobiles, trucks, buses, trains, aircraft, ships, and tractors. Gasoline makes up almost three-fourths of the fuels used in the transportation sector. The overall growth rate of gasoline has been curtailed as a result of the declining use of aviation gasoline.

"Jet fuel has had the highest growth rate of all the petroleum fuels in recent years. Nearly all jet fuel used in domestic commercial aircraft is the kerosene type. The military uses predominantly the naphtha type, which may be various blends of gasoline, kerosene, naphtha, and distillate fuels.

"Distillate fuel oil for home and commercial heating has been losing its share of the heating market to natural gas and electricity. The demand for residual fuel oil, used for heating large buildings and electricity generation, has been increasing at a fairly rapid rate since 1964, mostly as a result of use by electricity generation utilities. Utility use of residual fuel oil, instead of coal, increased substantially in the East after import controls were relaxed and air pollution restrictions were effected in some areas. The sale of fuel oil for heating and steam generation depends to a great extent on low-cost transportation from the refinery or port of entry to the marketing areas. Thus, the markets for these fuels are near coasts, the Great Lakes, and the major waterways, such as the Mississippi, Ohio, Illinois and Hudson, and near refining centers.

"The liquefied petroleum gas (LPG) fuels are used for cooking and heating in mobile homes and travel trailers, and in areas where natural gas or oil are not readily available. They are used for many types of transportation including passenger cars, buses, and trucks. In addition, LPG is used extensively on farms for brooders, for flame cutting and weeding, barn heating, crop drying, irrigation pumping, tractor and truck power, and poultry scalding and waxing. The growth rate of LPG in recent years has been second (among energy uses) only to that of jet fuel.

"The principal raw material use of petroleum is as a base input or feedstock for the production of petrochemicals...

"Raw materials used in the synthesis of organic chemicals include ethylene, acetylene, propylene, and butylene (all derived from liquefied gases), and naphtha, benzene, toluene, and xylene.

"Major petrochemical products are ammonia, carbon black, synthetic rubber, plastics and resins, and synthetic fibers.

"Asphalt and road oil constitute the second largest use of petroleum as raw material. Asphalt is used extensively for paving roads, making shingles and other building materials, waterproofing, and miscellaneous purposes. Its growth rate is governed to a great extent by both highway construction programs and general building activity.

"An important but slow-growing use of petroleum is for lubricants. The growth rate has diminished in recent years with improvements in lubricant quality, increasing use of turbine-type engines, and improved bearings.

"The principal uses of petroleum coke are for refinery fuel (71 percent) and making electrodes. Almost 12 percent of the 1968 coke demand was consumed as electrodes in alumina reduction plants. Another important use is for electrodes in electric motor brushes. Approximately 25 percent of coke production was exported, mostly to Japan, Canada, and Europe. The high sulfur content of some petroleum coke renders it unfit for many uses.

"Miscellaneous uses of petroleum include solvents, chemicals (oil base), wax products, pharmaceuticals, injection of LPG into oil reservoirs for secondary recovery purposes, protein synthesis and a wide variety of specialty uses. Wax consumption is now turning upward after several years of slump, and is regaining some markets in carton and paper coating it had lost to the plastics industry." (1)

Table 6 shows petroleum consumption by sector in 1970 with National Petroleum Council (NPC) projections for 1975, 1980, and 1985. Comparison of table 6 with table 3 is difficult because table 6 shows an "other" category which does not appear in table 3. Nevertheless, some marked differences in recent growth rates are apparent. From 1968 to 1970, while petroleum consumption grew slightly less than 10 percent, consumption in the utility sector rose 76 percent, due to the rapid shift from coal to low-sulfur residual fuel oil.

Table 6

U.S. PETROLEUM DEMAND BY SECTOR
(MB/D)

	1970	1975	1980	1985	AAI % 1970-85
Transportation	7,838	9,647	11,774	13,801	3.8
Residential/Commercial	2,607	2,898	3,104	3,299	1.6
Industrial	1,500	1,839	2,256	2,683	4.0
Utilities	910	1,697	2,345	2,665	7.4
Petrochem Feedstocks	818	1,163	1,586	2,089	6.5
Other	1,049	1,102	1,264	1,440	2.1
TOTAL	14,722	18,346	22,329	25,977	3.8%

Source: Reference (8, pg. 17)

NPC projects that demand by utilities and for oil as petrochemical feedstocks will increase at a faster rate than other uses, but that transportation will continue to claim approximately 53 percent of petroleum demand.

Table 7 shows Bureau of Mines contingency forecasts of components of consumption in the year 2000. Note that in each case, transportation use is expected to become increasingly dominant, rising from 55 percent of all petroleum uses in 1968 (table 3) to 74 percent in the low demand case or 69 percent in the forecast base case (table 7). Only in the high demand case (45.0 million barrels per day) would the transportation sector consume a smaller fraction (48 percent) of petroleum than it did in 1968.

B. Petroleum Supply

U.S. demand for oil is growing much faster than the available domestic supply. Exploratory activity has been declining since 1957, which has led to a similar decline in discoveries. Additions to proved reserves have been less than withdrawals in 6 out of the past 10 years, and our ability to produce oil declined in 1968, 1969, 1970, and 1971. The United States could have supplied, without imports, all of its requirements for petroleum from domestic fields until 1967. We are now some 1.5 million barrels per day short of being able to do so, and dependence upon foreign sources is increasing so that an additional three-fourths million barrels per day must be imported with each passing year.

Table 7

Petroleum consumption by major products and by major consuming sectors [1] year 2000, forecast base

	Household and commercial		Industrial		Transportation [2]		Electricity generation, utilities		Total domestic product demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
Fuel and power:										
Liquefield gases	30	121	40	160	75	300	...	...	145	581
Jet fuel (kerosine and naphtha types)	...	...	...	...	1,127	6,284	...	...	1,127	6,284
Gasoline	...	...	...	...	4,665	24,482	...	...	4,665	24,482
Kerosine	6	34	12	68	...	...	...	...	18	102
Distillate fuel	38	225	130	757	500	2,913	4	24	672	3,919
Residual fuel	18	114	271	1,704	200	1,257	133	837	622	3,912
Still gas	...	...	291	1,748	...	...	...	...	291	1,748
Petroleum coke	...	...	103	617	...	...	...	...	103	617
Total	92	494	847	5,054	6,567	35,236	137	861	7,643	41,645
Raw material: [3]										
Special naphthas	...	...	84	439	...	...	...	...	84	439
Lubes and waxes	...	...	50	299	60	364	...	...	110	663
Petroleum coke	...	...	120	722	...	...	...	...	120	722
Asphalt and road oil	226	1,506	...	...	...	...	...	...	226	1,506
Petrochemical feedstock offtake:										
Liquefied refinery gas	...	...			...	...	...	...		
Liquefied petroleum gas [4]	...	...			...	...	...	...		
Naphtha (−400°)	...	...	1,444	6,576	...	...	...	...	1,444	6,576
Still gas	...	...			...	...	...	...		
Miscellaneous (+400°)	...	...			...	...	...	...		
Total	226	1,506	1,698	8,036	60	364	...	...	1,984	9,906
Total domestic product demand	318	2,000	2,545	13,090	6,627	35,600	137	861	9,627	51,551

[1] Includes liquefied refinery gas and natural gas liquids.
[2] Includes bunkers and military transportation.
[3] Includes some fuel and power use by raw material industries.
[4] Includes LP gas for synthetic rubber.

—Petroleum consumption by major products and by major consuming sectors

	Household and Commercial		Industrial		Transportation		Electricity generation, utilities		Total domestic product demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
YEAR 2000 (LOW)										
Fuel and power:										
Liquefied gases	31	124	4	16	50	201	...	...	85	341
Jet fuels (kerosine and naphtha types)	...	...	...	...	960	5,353	...	...	960	5,353
Gasoline	...	...	...	...	3,883	21,652	...	...	3,883	21,652
Kerosine	6	34	1	6	...	...	...	...	7	40
Distillate fuel	38	222	13	76	420	2,449	...	...	471	2,747
Residual fuel	18	113	102	641	90	566	137	861	347	2,181
Still gas	...	...	223	1,339	...	...	...	...	223	1,339
Petroleum coke	...	...	81	487	...	...	...	...	81	487
Total	93	493	424	2,565	5,403	30,221	137	861	6,057	34,140
Raw material:										
Special naphthas	...	...	51	267	...	...	...	...	51	267
Lubes and waxes	...	...	39	235	40	243	...	...	79	478
Petroleum coke	...	...	41	247	...	...	...	...	41	247
Asphalt and road oil	225	1,499	...	...	...	...	...	...	225	1,499
Petrochemical feedstock offtake	...	...	890	4,053	...	...	...	...	890	4,053
Other	...	...	...	...	...	...	...	...	...	...
Total	225	1,499	1,021	4,802	40	243	...	...	1,286	6,544
Total domestic product demand	318	1,992	1,445	7,367	5,443	30,464	137	861	7,343	40,684
YEAR 2000 (HIGH)										
Fuel and power:										
Liquefied gases	500	2,004	66	264	90	361	...	...	656	2,629
Jet fuels (kerosine and naphtha types)	...	...	...	...	1,660	9,256	...	...	1,660	9,256
Gasoline	...	...	...	...	5,000	27,880	...	...	5,000	27,880
Kerosine	20	113	19	108	220	1,246	...	...	259	1,467
Distillate fuel	1,000	5,832	260	1,516	640	3,732	...	...	1,900	11,080
Residual fuel	370	2,327	387	2,434	215	1,352	1,200	7,544	2,172	13,657
Still gas	...	...	490	2,943	...	...	...	...	490	2,943
Petroleum coke	...	...	172	1,034	...	...	...	...	172	1,034
Total	1,890	10,276	1,394	8,299	7,825	43,827	1,200	7,544	12,309	69,946
Raw material:										
Special naphthas	...	...	95	496	...	...	...	...	95	496
Lubes and waxes	...	...	63	380	65	394	...	...	128	774
Petroleum coke	...	...	200	1,203	...	...	...	...	200	1,203
Asphalt and road oil	550	3,664	...	...	...	...	...	...	550	3,664
Petrochemical feedstock offtake	...	...	2,970	13,525	...	...	...	...	2,970	13,525
Other [1]	...	...	160	880	...	...	...	...	160	880
Total	550	3,664	3,488	16,484	65	394	...	...	4,103	20,542
Total domestic product demand	2,440	13,940	4,882	24,783	7,890	44,221	1,200	7,544	16,412	90,488

[1] Miscellaneous uses including natural gas liquids used in secondary recovery operations and oil used in protein synthesis.

Source: Reference (1, pg. 173)

Increasing dependence on foreign oils has been brought about by two converging trends: (1) The increasing use of oil to help offset the supply lag by the other energy commodities, and (2) decreasing ability to meet the increased oil requirements from domestic sources. The convergence between demand and supply has important political and economic implications that are analyzed in the discussion which follows.

The present oil situation is the result of events that began 25 years ago, when demand for all goods and services exploded following the relaxation of World War II controls. Responding to sharply higher demands for oil, the petroleum industry increased exploration and applied newly developed production technology. At the same time, rising foreign oil imports began to dampen the growth in demand for domestic oil and demand was further slowed following the 1956-58 recession. Supplies of oil, therefore, increased much faster than demand, and large amounts of spare producing capacity developed (figure 6). The over-supply conditions peaked in 1964, when the Nation could have increased production by nearly 40 percent. Over most of this period, the wholesale price of oil remained virtually unchanged.

With an ever-increasing amount of supply and a relatively stable wholesale price, the petroleum industry had neither the need nor the economic incentive to spend money to develop new oil supplies (figure 7). However, large sums of money have been expended in recent years to acquire leases, which strongly suggests that the industry has been preparing a base for renewed exploration and development (2).

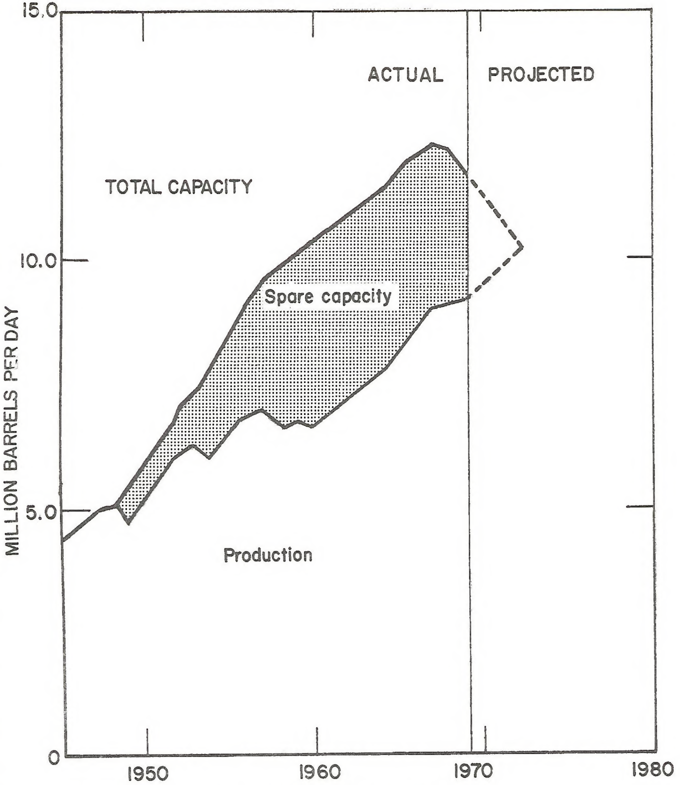

Figure 6 .– U.S. Crude oil producing capacity.

Office of Oil and Gas
Department of the Interior
(Excludes Alaskan North Slope)

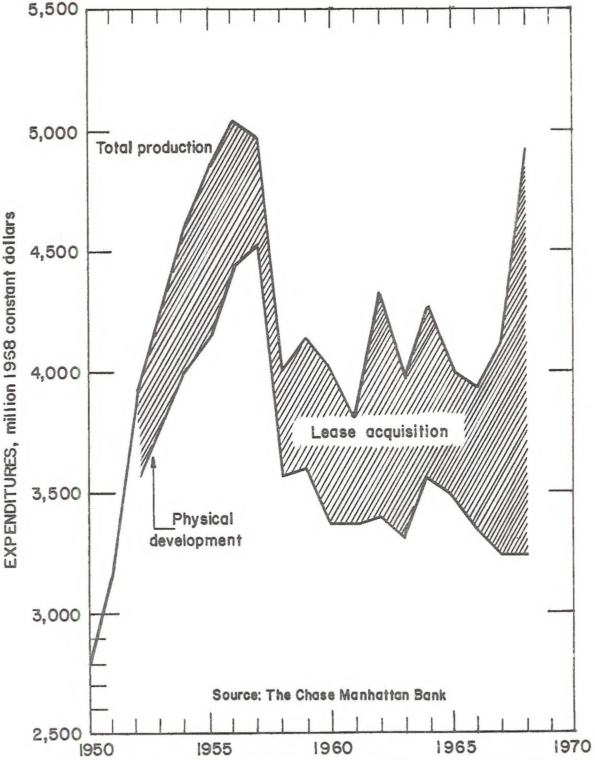

Figure 7. – Expenditure for total production, lease acquistion, and physical development.

Source: Reference (2, pg. 5)

New additions to productive capacity must be developed if this Nation is to continue to have some spare capacity for emergency conditions, since all of the spare capacity we now have will be gone by 1973 at the present decline rate. Over the short term, these trends can be altered by technology, prices, and foreign oil imports. Over the longer term, the development of the Nation's vast supplemental energy sources can provide the flexible supply options that will be needed to stabilize the energy situation.

1. Crude Petroleum Recovery

The recovery of petroleum from known oil fields has followed a gradual evolutionary process, responding to both improving technology and the changing character of the discovered fields. The earliest period of the petroleum industry was characterized by a lack of understanding about how best to produce oil, and many fields were abandoned following the cessation of primary flush production. Substantial improvements in oil recovery were made during the 1920-40 period, with the discovery of many of the Nation's major natural water-drive fields (East Texas, for example). After 1940 the overall trend was the discovery of oil fields which were not capable of yielding as high a recovery efficiency as those discovered in the 1920-40 period. The decline in reservoir quality, however, was gradually offset by the introduction of formation fracturing and the large-scale application of secondary recovery.

A constantly improving production technology has permitted the average recovery from a field to increase at an estimated annual rate of about 0.5 percent over the past 20 years: the current total recovery is about 31 percent of the oil that has been discovered to date. This trend is due mainly to the injection of water into oil fields to supplement or replace the natural energy of the field. Improvements are being made, but the types of oil fields now being found are not as susceptible to this technique as those that were found in the past.

The interrelationship between price, technology, and supply has been described (3) and is illustrated in figure 8.[1/] As shown, the amount of "proved reserves" plus those estimated as "economically producible" at current prices totaled about 49 billion barrels in 1965. An additional 22 billion barrels was estimated as physically recoverable using conventional fluid injections, but this oil is contained in marginal fields and the application of the technology is more costly. The last category in figure 8, "recoverable using new technology," refers to the application of miscible fluid drive and in situ combustion to recover oil, but widespread application of these techniques could be justified economically only if the price

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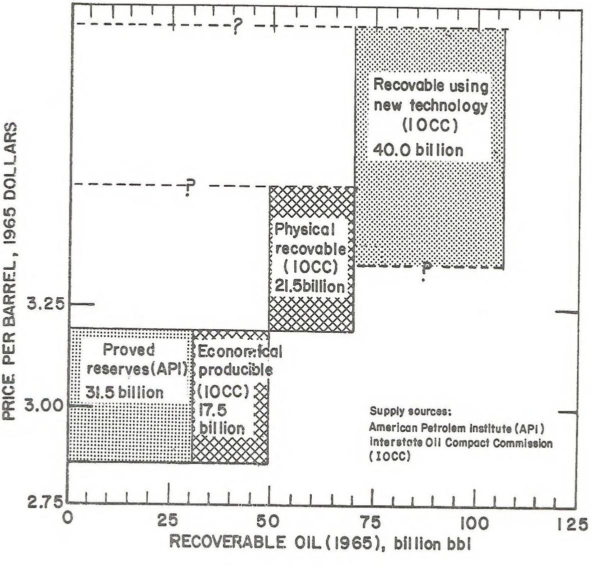
1/ The Interstate Oil Compact Commission last made estimates in 1965 of the amount of oil that could be produced by secondary recovery if such techniques were actually applied to know oil fields. Although the data was dated, the supply-price concept discussed above is valid.

Figure 8. - Petroleum recovery depends on Technology.



Source: Reference (3, pg. 125)

of oil were to advance significantly. Complete adoption of all recovery methods where applicable to existing oil fields could physically recover nearly 100 billion barrels of oil from these fields.

Production of crude oil from known reservoirs, therefore, depends on both technology and oil prices. Higher prices and/or improved technology would make it profitable to extract substantial amounts of additional oil from fields which are now economically marginal. Our ability to continue to advance technology and the economic availability of energy supplies from oil shale, coal, and tar sands will determine future price relationships for energy sources.

2. Increased Discovery

No matter how efficient and sophisticated recovery techniques become, they necessarily must follow and depend upon initial discoveries made by exploratory drilling. Since the act of discovery is the genesis of proved reserves, discovery trends and related technology have been intensely studied (4,5,6). The voluminous data developed in these efforts show that:

1. Exploratory drilling has consistently declined for the past 15 years, the longest decline in the history of the industry.
2. New oil discoveries have also followed the downward trend.
3. Except for Northern Alaska, the oil deposits found are getting smaller since the most favorable prospects have been discovered and developed first.

4. The cost of exploration and development is increasing sharply as deeper formations are probed both on land and in more costly offshore and Arctic environments.
5. Discovery technology is in a mature state of development and only evolutionary improvements can be expected.

The 1968 discoveries of oil on the North Slope of Alaska and in some offshore areas are exceptions to the record of the U.S. petroleum industry, which can otherwise be characterized as a mature extractive industry well into the decline stage of its discovery cycle. Although many billions of barrels of oil have been discovered in the Arctic, oil from this region could be limited by the availability of adequate transportation to markets. If the Trans-Alaska pipeline is constructed as proposed, about 2 million barrels per day of oil from Alaska will be available by 1980. While this involves a significant amount of oil, it will only supply a fraction of the increase in demand between 1970 and 1980. The United States must continue to look to the Lower 48 States and the Outer Continental Shelf for a major portion of future domestic supplies. Production increases in those areas can occur only if the tempo of exploration is significantly and successfully expanded.

Extensions of old fields and discoveries of new fields at conventional or greater depths are forecast for all regions covered by the extensive study completed by the National Petroleum Council in

1970 (7). Indeed, the total volume of undiscovered oil and gas in this Nation is expected to equal or surpass the volume that has been discovered from 1859 to the present. However, there is little likelihood of a technical breakthrough that will significantly alter discovery rates.

It is not possible to accurately predict the amount of oil that will be discovered and recovered in the future. Advances in exploration and recovery technology, the randomness of discovery, economic incentives, and Government policies related to leasing, foreign oil imports, taxation, price controls, and supplemental source development all bear directly on future oil supplies from domestic sources. But even if a significantly increased exploratory effort were started immediately and were highly successful, from 5 to 10 years would be required before the new discoveries could be developed into producing oil fields with significant output.

3. Projected Supplies of Domestic Crude Petroleum (8)

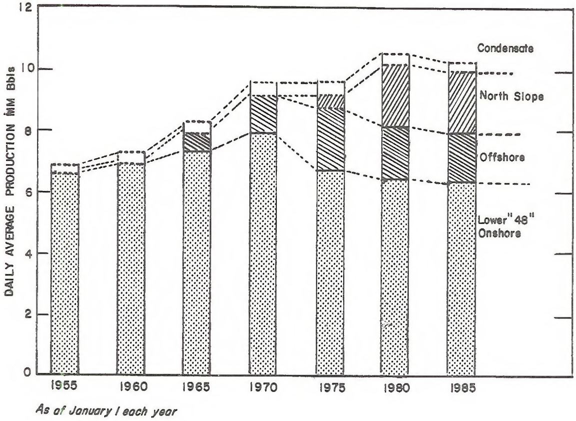
The expected domestic production of crude oil and condensant is indicated in Table 8. The geographic distribution of production is indicated on bar graphs in Figure 9. Except for Northern Alaska, domestic productive capacity is expected to be reached in the early 1970's. As indicated earlier in Table 1, 23.56 MM b/d are projected as the need for liquid fuels in 1985. The difference between the 10.11 MM b/d potential production and the need represents the shortfall that must come from some other source--imports or substitute fuels.

4. Foreign Oil Imports

The United States is critically dependent upon liquid and gaseous fuels that presently can only be obtained, in the quantities needed, from conventional petroleum sources, both foreign and domestic. This will remain true for the next 10 or more years regardless of the progress made in the extraction of liquids and gases from coal and oil shale, because long lead times are necessary to develop these supplemental sources. The adequacy, security, and cost of petroleum supplies have a direct influence on the Nation's national product, trade position, diplomatic posture, and military capability.

Under these circumstances, Government has the responsibility to encourage a favorable administrative and economic climate under which the Nation's petroleum industry can provide oil and gas supplies that are both secure and adequate, at the lowest practicable cost, and with minimal environmental impacts. In addressing itself to this responsibility, the Federal Government in 1959 made the fundamental determination that unless the domestic market were shielded from foreign supplies, too large a share of it would eventually come to be dependent upon foreign sources, subject to denial by either political or military action. With security of supply as the primary criterion to be satisfied, a policy and program restricting foreign oil imports to a moderate fraction of domestic production was enacted.

Figure 9. - U.S.A. Oil Supply



Source: Reference (8, pg. 29)

Table 8 - Projected Oil Supply

TABLE 8

PROJECTED PRODUCTION--ALL SOURCES
(MMB/D)

	Total U.S.A.			U.S.A. Without North Slope		
	Crude Oil	Condensate*	Total	Crude Oil	Condensate	Total
1970	9.10	0.37	9.47†	9.10	0.37	9.47
1975	9.15	0.38	9.53	8.55	0.38	8.93
1980	10.10	0.33	10.43	8.13	0.30	8.43
1985	9.87	0.24	10.11	7.90	0.21	8.11

* Includes Lease Condensate.
† API source; U.S. Bureau of Mines shows 9.63.

Source: Reference (8, pg. 29)

The potential insecurity of Middle East oil supplies is evidenced by the history of the past 20 years. In 1951 the seizure and shutdown of oil facilities in Iran virtually stopped all oil exports from that country for over 2 years. The Suez Canal, closed by Egypt for a period of 5 months in 1956, was again closed in 1967, and remains closed at the time of this writing. The 1967 outbreak of hostilities between Israel and the Arab Nations interrupted, for a brief interval, over two-thirds of the oil supply to Western Europe. Moreover, a 2-month embargo was imposed on oil shipments to the United States, the United Kingdom, and the Federal Republic of Germany by certain oil-exporting nations. The Trans-Arabian pipeline was ruptured in May 1970. Its repair was delayed by the Syrian Government throughout the balance of the year. Concurrently, the Libyan Government sharply curtailed production from oil fields located in that country. These actions placed tremendous pressure on the world's tanker fleets, forcing upward the costs of chartering tankers to transport this crude.

These interruptions in oil supplies occurred at a time when substantial switches from coal to imported residual oil were being made to meet environmental standards. Sharply increased residual oil demand and limited availability of transport caused the price of residual oil to increase by nearly 65 percent over the first 10 months of 1970. This development largely was the result of dependence on foreign sources and

lack of adequate transportation. Today, nearly 94 percent of the East Coast demand for residual oil is supplied by foreign imports. Of even greater concern, the supply source is shifting from the relatively secure South American oil fields to those of the more unstable North African area, as suppliers seek the low sulfur oil needed to meet environmental standards.

In the case of crude oil, spare domestic supplies were drawn down. Production from wells located principally in Texas and Louisiana was increased, and by November 1970, total production exceeded 10 million barrels per day for the first time in the Nation's history. This daily production rate, 500,000 barrels (or about 5 percent) greater than the average rate during the first 6 months of 1970, served to replace the deficit in overseas supplies. This action was possible during 1970, but by 1973 spare productive capacity will be eliminated and it will no longer be possible to increase the oil output from Texas and Louisiana wells.

The 1970 broken pipeline in Syria and production cutback in Libya affected less than 3 percent of the free world's oil supply, but this 3 percent is all it took to force a major readjustment in world movements of oil. Today, about 40 percent of the total oil needs of the world are supplied by output from fields located in the Middle East and Northern Africa. These areas, moreover, have about 70 percent of the free world proven oil reserves. Thus, the rapid increases in world

demand that are now taking place must force increasing reliance on these highly unstable supply sources. A new dimension to international oil movements must also now be considered--the demonstrated ability of the oil-exporting nations to act both separately and in unison to attain specific economic objectives at the expense of both the oil companies and consuming nations. Increasingly, the exporting nations have won price concessions from producing companies which ultimately must be paid for by consumers. The balance has now been tipped in favor of the oil-exporting nations.

Oil is being used increasingly as a tool for obtaining political and economic objectives. In its supplemental energy fuels, however, this Nation has within its own borders the oil equivalent of several Middle East oil fields. Technology for economic production of this oil from our oil shale, coal, and tar sand resources must be developed if oil supplies from these sources are to be available to meet future fuel needs.

5. Supplemental Sources

Each of the supplemental sources (coal, oil shale, tar sands) contain vast quantities of recoverable solid organic materials that are convertible to liquid and gaseous products. The oil represented by all of these deposits in place is not measured in billions of barrels, as is petroleum, but in trillions of barrels.

Most recent studies indicate that each of the supplemental sources is nearly competitive economically with crude oil using processes currently known but not yet commercially proved. Moreover, these processes involve large-scale material handling which lends itself to technological breakthroughs that may lead to substantial cost reductions. Scaling up from the current prototype development state to multi-billion-dollar industries will require years to plan and construct both the industry and supporting communities. In addition, the commitments of capital required for construction of operating plants alone will range from $3,000 to $5,000 per daily barrel of production; or from $3 billion to $5 billion for a 1-million-barrel-per-day output.

Oil shale economics have significantly improved relative to crude oil since this Department completed its last comprehensive analysis (9). Between 1966 and 1970, for example, costs have increased about 45 cents per barrel for the system identified in the referenced study as the "improved first generation" retorting option. This cost increase, however, has been balanced by crude oil prices which have risen by about $0.45/bbl. In addition, the Tax Reform Act of 1969 changed the point of application for calculating depletion from the oil shale before entering the retort to the shale oil as it leaves the retort, a change which increased the tax allowance by about $0.15 per barrel. Since shale-oil economics have remained about unchanged or have been slightly improved, while those of crude petroleum have declined, the

economic viability of shale-oil production has been enhanced when compared to crude petroleum. The alternative that proves to be most economical will depend on the positions of individual firms as they evaluate their resource situations and future needs. Many firms may meet their needs only through exploration and development of conventional sources; others will move toward the development of alternative sources.

The state of technology, the size of the investments required to develop supplemental sources as compared to alternative investment opportunities (i.e., Alaskan and offshore oil), and the planning and associated long lead time indicate that oil production from any of the supplemental sources cannot be a significant part of total supplies until after 1980. The potential for the more distant future, however, is great.

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IV. OIL SHALE: RESOURCES AND POTENTIAL

Large areas of the United States are known to contain oil-shale deposits, but those areas in Colorado, Utah, and Wyoming that contain the shale-rich sedimentary rocks of the Green River Formation are of greatest promise for shale-oil production in the immediate future (Fig. 10). These oil shales occur beneath 25,000 square miles (16 million acres), and of this area, 17,000 square miles (11 million acres) is believed to contain oil shale of potential value for commercial development in the foreseeable future.

The known Green River Formation deposits include high-grade shales, in beds at least 10 feet thick and yielding 25 or more gallons of oil per ton, that contain about 600 billion barrels of oil.[1/] Recovery of even a small fraction of this resource would represent a significant energy source adequate to supplement the Nation's oil supply for many decades, providing economic and environmentally safe methods of shale-oil production are developed.

It has long been known that petroleum liquids and gases can be obtained by heating oil shale in a closed vessel called a retort. Commercial production of shale oil abroad actually preceded by several decades the drilling of the first oil well in the United States. Shale-oil industries have been established in many foreign countries in the past and exist today in mainland China and the U.S.S.R. Although the Ute Indians used

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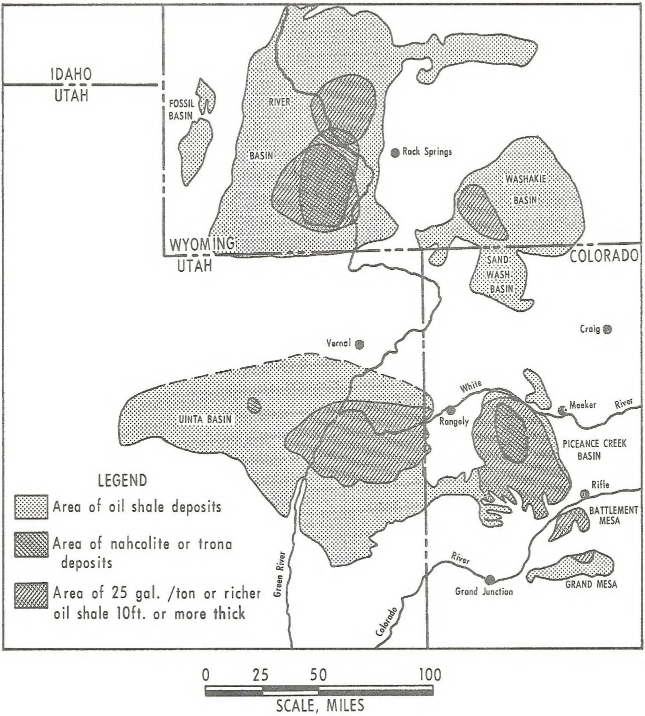
1/ An additional 1,200 billion barrels are present in place in lower-grade shales, in sequences more than 10 feet thick that have an average yield of 15 to 20 gallons per ton.

Figure 10 Oil Shale areas in Colorado, Utah and Wyoming



oil shale for campfires long before the first settlers arrived in Colorado, Utah, and Wyoming, interest in the commercial development of this extensive potential source of energy has fluctuated widely. Some oil from shale was produced prior to the 1859 discovery of natural petroleum, but industrial attention did not focus on oil shale until immediately prior to 1920, when there was some concern that domestic petroleum resources might become inadequate. Interest declined at that time as ample supplies of liquid petroleum were discovered and developed. Oil-shale deposits were withdrawn from leasing pursuant to Executive Order No. 5327 of April 15, 1930, subject to certain later modifications (1) which authorized leasing of oil and gas and sodium in accordance with the terms of the modifications.

The Synthetic Liquid Fuels Act of April 5, 1944, as amended [(30 USC § § 321-325) the Act now expired], made possible a large-scale oil-shale research and demonstration effort by the Department of the Interior's Bureau of Mines during the period 1944-56. This effort was aimed at the creation of a new and more economic mining, retorting, and refining technology, and also sought to provide reliable information on the costs of commercial shale-oil production. Industry has also conducted extensive research on oil shale processing; several methods have advanced through the demonstration phase as discussed elsewhere in this study.

The Department's accumulated knowledge of this resource and its expected potential were summarized in a comprehensive 1968 Interior study (2). Contemporary and future technologies, and the public policy factors that could influence the rate of development of this resource were clearly delineated. Included also were estimates of the resource size and land ownership status. Efforts since the study's publication have been concentrated on: (1) An analysis of the probable environmental impact of oil-shale development, (2) the formulation of a prototype leasing program within the framework of existing law, and (3) a program to determine ownership of the oil shale where title conflicts exist.

Commercial shale-oil production, under the most optimistic estimate, could begin about 1975 at a rate of about 18 million barrels per year (50,000 barrels per day), on the basis of anticipated technologic progress. The first generation technology needed for this rate of production would be improved from 1976 to 1980. This development stage will be reflected by only small increases in annual production of about 18 million barrels per year as the new technology is applied. By 1980 a productive capacity of more than 100 million barrels per year (300,000 barrels per day) could be established. More importantly, the technology probably will have been advanced to the point where large incremental increases in production could be achieved. Also,

the nucleus of people, supporting services, facilities, and experience needed for this expanded effort will have been established.

After 1980 the second generation extraction-retorting systems would be expected to permit annual additions to shale-oil productive capacity of about 37 to 73 million barrels per year (100,000 to 200,000 barrels per day). The rate at which oil shale may be developed provides the framework within which subsequent calculations may be made, considering both the stage of technology and the size of the capital investments that will probably be required. Seven installations with a cumulative capacity of 400,000 barrels per day are assumed to be constructed on both private and public lands in the period 1973 to 1981, as shown in Table 9. In the period 1981 to 1985 capacity is assumed to grow to one million barrels per day.

The cumulative 6-plant capacity of 300,000 barrels per day by 1979 reflects the necessary construction and evaluation phase of this new technologic development. Second generation technology could be expected to be available by 1980, enabling the large increases in capacity from surface processing systems shown in Table 9. In situ retorting may also be advanced to the point where the first commercial operation could be initiated. By 1985 cumulative capacity is estimated at 1 million barrels per day from both private and public lands.

Table 9. Projected Shale Oil Capacity - Cumulative

(Thousands of Barrels per day)

	Colorado		Utah	Wyoming	Total
	Federal land	Private land	Federal land	Federal land	
1973	--	--	--	--	--
1974	--	--	--	--	--
1975	--	--	--	--	--
1976	--	50	--	--	50
1977	--	50	--	--	50
1978	50	100	--	--	150
1979	150	100	--	--	250
1980	150	100	50	--	300
1981	150	150	50	50	400
1982	--	--	--	--	550
1983	--	--	--	--	700
1984	--	--	--	--	850
1985	--	--	--	--	1,000

A. References Cited

1. See Executive Orders No. 6016 of February 6, 1933 and No. 7038 of May 13, 1935; Public Land Order No. 4522 of September 23, 1968.

2. U.S. Department of the Interior, Prospects for Oil Shale Development, Colorado, Utah, and Wyoming, Washington, D.C., 1968, 134 pp.

V. ALTERNATIVES TO OIL SHALE DEVELOPMENT

The principal alternatives to the proposed prototype oil shale leasing program are of two types; those that can be implemented through public policies and those that can be implemented by substituting one energy form for another. The alternatives are not mutually exclusive and, therefore, interact. They are separated in this document only to facilitate the discussion. The principal environmental impacts are considered under the discussion of each commodity, beginning with Chapter V-C, "Alternatives to Oil Shale Development."

A. Alternative Oil Shale Policies [1/]

There are four broad alternatives to the proposed program. The first of these is development of public lands by the Government; the second is for the Government to take no steps to develop oil shale resources on public lands; the third is for the Government to postpone development of the public oil shale lands at present, but to re-assess its position at regular intervals, with a view toward potential development at a future date; the fourth is open leasing

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1/ Alternatives to oil shale development have been examined in a number of publications. See for example: Oil Shale Advisory Board, Interim Report to the Secretary of the Interior, Washington, D.C., February 1965; Competive Aspects of Oil Shale Development, Senate Hearings before the Subcommittee on Interior and Insular Affairs, United States Senate, 90th Congress, 1st Session, February and September 1967.

of public lands. Each of these policy alternatives is considered briefly below:

Government Development of Public Oil Shale Lands - There are a number of possible options for Federal development of the Nation's oil shale resources, including: (1) a government-financed demonstration plant; (2) a joint government-industry effort, in which costs are shared equally; (3) a government corporation, modeled upon COMSTAT (The Communication Satellite Corporation); and (4) a government organization modeled after the TVA (Tennessee Valley Authority). Precedent exists for each of the four options for government development, but none of the alternatives that involve extensive government participation are authorized by existing legislation as it pertains to oil shale. Clearly, it is not the intent of Congress to establish such a precedent as it pertains to mineral resources. The policy of Congress embodied in the mineral leasing laws has been recently supplemented by the Mining and Minerals Policy Act of 1970 (84 Stat. 1876) which states that -

> . . . it is the continuing policy of the Federal Government in the national interest to foster and encourage private enterprise in (1) the development of economically sound and stable domestic mining, minerals, metal and mineral reclamation industries, (2) the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security and environmental needs, (3) mining, mineral, and metallurgical research, including the use and recycling of scrap to promote the wise and efficient use of our natural and reclaimable mineral resources, and (4) the study and development of methods for the disposal, control, and reclamation of mineral waste products, and the reclamation of mined land, so as to lessen

> any adverse impact of mineral extraction and processing upon the physical environment that may result from mining or mineral activities.

The Secretary of the Interior has been assigned the responsibility to carry out these policy directives in exercising his authority under the mineral leasing laws.

Oil shale development on public lands was studied by the Public Land Law Review Commission 1/ which recently completed its charter to study and recommend to Congress legislation providing for, among other things, more effective administration of public lands and mineral resources. Concerning oil shale development, that Commission recommended that -

> Some oil shale public lands should be made available now for experimental commercial development by private industry with the cooperation of the Federal Government in some aspects of the development.

Further, the Commission suggested that -

> . . . to be viable such a program should: (1) offer for lease, tracts sufficiently large to permit amortization of investments required for commercial development; (2) give weight to industry nominations relating to location and size of tracts, lease duration, and size of plant; (3) not bar the holder of a test lease from eligibility for leases subsequently issued under a general leasing program; (4) include experimental use of bonuses, royalties and rentals; (5) provide fixed terms, conditions, and royalty payments for the term of the lease; and (6) not interfere with process patent rights of lessees acquired prior to issuance of the leases.2/

1/ Established by the Act of September 19, 1964, as amended, (43 U.S.C. §§ 1394-1400).

2/ Public Land Law Review Commission, One Third of the Nation's Land, Washington, D.C., 1970, p. 135.

The proposed prototype program is consistent with the Congressional policy directives and the recommendations of the Public Land Law Review Commission described above.

Regardless of the organizational method, physical development of the resource would proceed along the lines described in Chapter I of this document. Thus, the environmental impact of any development is expected to be essentially the same as that described in other sections of this report.

No Development of Public Oil Shale Lands - The government could determine to take no steps to develop oil shale resources on public lands. This would mean that there would be no direct environmental impact on public lands, but there might still be oil shale development on other lands. There are at least three oil shale tracts in private ownership which are sufficiently large to support operations, but neither their commercial potential nor the willingness of their owners to permit development can be assessed by the Department.

If there is sufficient interest in oil shale on public lands, then development on private lands might be commenced. Generally speaking, conditions on private lands containing adequate reserve potential are believed to be similar to those with the same potential on the public lands in the oil shale area, and, therefore, the environmental impact would probably be similar. From such development, there might also be an indirect environmental impact on adjacent

public lands. Development on private oil shale lands would proceed under environmental standards of Federal and State governments, but special environmental standards of the kind which it is proposed to tailor for each lease offered under the proposed prototype program would not necessarily be made applicable. Any successful oil shale development on private lands would probably lead to renewed demands for development on public lands, and, in that event, the dangers of a crash program discussed below might arise.

Delay Development on Public Lands - The government could delay the initiation of an oil shale program on public lands, and re-assess the situation from time to time to determine whether such a program should be started. This would avoid, on a short-term basis, any effect on the environment, but in the long run the effect could prove more harmful. Potential environmental impact would probably be the same at a later date, but many of the things which must be learned to protect the environment cannot be learned except by actual experience. Delay or postponement of the proposed program may reduce the available time that is needed to resolve many technical and environmental uncertainties. Up to ten years would be required for that task under normal circumstances. Prolonged delay may leave no alternative but to react eventually with a crash program to develop this resource.

By their nature, crash development programs frequently sacrifice environmental considerations and regional planning to technologic expediency. The balanced progress needed to resolve the complex interrelationship between the environment and technology is denied and orderly development is not possible.

Open Leasing - One alternative to the proposed action of a prototype leasing program would be for the Department to implement an open-leasing policy permitting the various companies interested in oil shale development to acquire rights and start development as soon as possible.

Such a leasing policy would still limit, under the Mineral Leasing Act of 1920, any company or individual to a maximum of one 5,120-acre lease or equal accumulated leased acreage in several leases if they were not the lessee. Open leasing is defined as the Department issuing leasing regulations, and then offering for competitive leasing such acreage as might be nominated by private interests.

Such a policy would require all actions to be in accord with the National Environmental Policy Act of 1969 and the applicable Federal and State Regulations. However, the manner of bidding and terms of the lease may be different than that considered under the proposed prototype program. These options have been detailed in the Department's 1968 publication entitled Prospects for Oil Shale Development.

Regardless of the objective and specifics of such an open-leasing policy, the rate that oil shale can be developed is initially fixed by the availability of venture capital and the time required for technologic development. The analysis presented in this regional impact document has stressed the maximum rate of development through 1985 from the development of both public and private leases. Thus, an open leasing policy would not change the analysis presented herein.

If the terms of the leases to be offered under an open leasing policy were to encourage early development, this would delay indefinitely the impact from private holdings. Thus, it is conceivable that the full one million barrels per day production established as the maximum 1985 rate would be from public lands. If this is the maximum that can be supported by the holdings under this open leasing policy, subsequent development would be from lands now in private lands. The potential from these lands was estimated at 400,000 barrels per day; therefore, industry would be able to expand the total production by 40 percent over the maximum 1985 level without the full environmental review that would be conducted under the proposed prototype leasing program.

Conversely, if the leasing terms under the open leasing policy did not encourage development at an early date, the potential impact may be delayed indefinitely while industry attempts to develop its holdings. Some of the public lands would also need to be developed to attain the maximum 1985 production level, but development on public lands after 1985 could increase to the ultimate production level---again without the public and government participation in environmental review that would be conducted under the proposed prototype leasing program.

Open leasing would, therefore, result in environmental impacts similar to those described in this document through 1985. However, it could result in significantly increased production after 1985 without the planned evaluation to assess the actual magnitude of the environmental consequences of development.

B. Alternative Energy Policies

1. Reduction in Demand for Energy

One alternative to the production of 1 million BPD of shale oil by 1985 is to, in some manner, reduce the need for liquid energy products by that quantity in the year 1985. This alternative, in the time frame of this report, would be an extremely difficult one to implement. Examination of this alternative follows in the discussion below.

Earlier in this report it was noted that energy demand correlates closely with gross national product (GNP) which, in turn, correlates closely with both population and per-capita income. The increasing use of energy has therefore been correlated with increasing affluence and a rising material standard of living. In part, perhaps because the economic cost of energy has not taken full account of environmental costs, and because supplies of resources have been ample, growth in energy demand has been little constrained by its cost. Now, however, in the face of increasing concern over the quality of the environment, declining energy resources, and a high material standard of living, it is appropriate to consider whether historic energy consumption patterns should be allowed to continue unabated. A number of writers have argued that it should not. Among the more recent works are those of Prof. Meadows and a group at MIT working in collaboration with the Club of Rome's project on the Predicament of Mankind (1), the "Blueprint for Survival" statement published in the Ecologist (2), and an article by Michael McCloskey, executive director of the Sierra Club (3), Professor Commoner (4), has warned of the consequences of continuation of current technological trends.

Not all scholars agree with such arguments. Drs. Kneese and Ridker of Resources for the Future (5) and Dr. Abelson, president of the Carnegie Institution and editor of Science (6), take issue with results of the MIT project, for example, principally on grounds that technological improvements have kept pace with demand in the past, and are likely to do so in the future.

There are essentially two ways of reducing the growth in energy demand: (1) Reduction in population growth and (2) reduction in per-capita energy consumption. Both measures could be encouraged by government policy. In the absence of such policies, the current base forecast of the Bureau of Census (series D) (7) shows population growing as follows (comparison is with Bureau of Mines energy forecasts) (8):

Year	Population (million)	Percent change	Total energy consumption (trillion Btu)	Per capita consumption (million Btu)	Percent change
1970	204	-	68,810	337	-
1975	216	+ 6%	88,612	410	+22%
1985	240	+11%	133,396	556	+36%
2000	288	+20%	191,556	665	+19%

Clearly, the increase in per capita consumption is far more important to growth in energy demand than the growth in population. At the extreme of replacement fertility and no net immigration (the Bureau of Census's Series X) (9) growth trends would be:

Year	Population (million)	Percent change	Total energy consumption (trillion Btu)	Per capita consumption (million Btu)	Percent change
1970	204	-	68,810	337	-
1975	214	+ 5%	88,560	410	+22%
1985	233	+ 9%	129,548	556	+36%
2000	256	+10%	170,240	665	+19%

The continued increase in population to the year 2000, despite a zero population growth rate, is due to the age distribution and consequent fertility expectations of the existing population.

Population growth trends are in a transitional phase; United States population growth rates appear to be declining without government intervention. The most likely rate of growth of population is the Bureau of Census's Series D, which increases only 1.0 to 1.2 percent per year through 1985 (10). Thus, only about 1 percent of the growth in energy demand of about 4 percent can be attributed to increased population. Increased per-capita consumption with per-capita income and income growth contribute the balance (about 3 percent). Thus little significant effect on energy demand can be made by altered population trends.

A reduction in the rate of growth of per-capita energy demand could be accomplished by (1) reducing the rate of growth of demand for the goods and services produced by the energy demanded, (2) producing the demanded goods and services more efficiently, or (3) converting energy sources to useful work more efficiently. Examples of measures to reduce the rate of growth of per-capita energy demand, especially in the petroleum sector, include (1) a trend toward smaller cars and increased use of mass transit; (2) increased use of insulation to reduce energy requirements for heating and air conditioning; and (3) advances in technology of extraction of energy from fuels, such as magnetohydrodynamic (MHD) power generation, and breeder-reactors. Improved efficiency of conversion is discussed elsewhere under specific alternatives; however,

in regard to mass transportation, a recent review (11) pointed out that mass transit would only affect intracity transportation. The report stated that whereas only 14 percent of all commuters use public transportation, commuting accounts for one-fourth of all passenger car useage. The impact of a doubling of the availability of mass transit in the next 15 years was shown to reduce total automobile useage by 4 percent and gasoline by only 3 percent.

Another possibility of reducing overall demand of energy products is to limit economic growth. The basic premise is that industrial and economic growth and clean environment are mutually incompatible. In this regard, the review (11) concluded that:

> "In the 15 years between 1950 and 1965, the U.S. labor force increased by 12 million. It took an average annual increase in Real Gross National Product of 3-3/4 percent to provide jobs for these new workers. By comparison, 23 million people will enter the labor market between 1970 and 1985; and assuming that there is the same rise in productivity as we experienced between 1950 and 1965, it will take an annual increase in Real Gross National Product of 4-1/4 percent just to keep unemployment at the current level.
>
> With these figures in mind, the impact of zero economic growth on the job market and national economy is clear.
>
> What the advocates of the zero economic growth philosophy seem to minimize is that society is going to need the jobs and goods and services that industry provides. Advocating zero growth also means telling the disadvantaged members of our society, who strive for a better way of life, that their goals are unattainable.

To reduce energy demand by the equivalent of the projected 1985 shale-oil production would entail reduction of energy consumption from petroleum by an estimated 4.2 percent. The mechanisms by which demand

would be reduced are not yet clear. All entail some method--generally forcible--of altering consumption patterns. Higher prices, legislation on maximum horsepower, or rationing are examples. Mr. McCloskey suggests:

> "A short-run strategy would involve the following changes in public policy: ending or reducing the many biases in public policies which provide incentives to energy growth; maintaining and strengthening environmental constraints on energy growth; reducing energy demands by educating the public to understand the importance of conservative use of energy; encouraging intensified research and development in order to achieve greater efficiencies in energy utilization and in order to find new, more environmentally acceptable, energy sources; and discouraging growth in industries that are the most profligate consumers of energy. Coordination of these efforts would be facilitated through the establishment of new government agencies, specifically geared to respond to the energy problem. Each of these changes would involve efforts that would go well beyond the traditional bounds of energy policy, and all could have profound economic and social impacts. Yet changes are already beginning to occur in all these fields, and environmentalists are determined to promote them." (12)

The "Blueprint for Survival" provides the following "strategy for change":

> "The principal conditions of a stable society--one that to all intents and purposes can be sustained indefinitely while giving optimum satisfaction to its members--are: (1) minimum disruption of ecological processes; (2) maximum conservation of materials and energy--or an economy of stock rather than flow; (3) a population in which recruitment equals loss; and (4) a social system in which the individual can enjoy rather than feel restricted by, the first three conditions.
>
> "The achievement of these four conditions will require controlled and well-orchestrated change on numerous fronts and this change will probably occur through seven operations: (1) a control operation whereby environmental disruption is reduced as much as possible by technical means; (2) a freeze operation, in which present trends are halted; (3) a systemic substitution, by which the most dangerous components of these trends are replaced by technological substitutes, whose effect is less deleterious in the short term, but over the long-term will be increasingly ineffective; (4) systemic substitution, by which these technological substitutes are replaced by "natural" or self-regulating ones, i.e. those which either replicate or employ without undue

disturbance the normal processes of the ecosphere, and are therefore likely to be sustainable over very long periods of time; (5) the invention, promotion and application of alternative technologies which are energy and materials conservative, and which because they are designed for relatively "closed" economic communities are likely to disrupt ecological processes only minimally (e.g. intermediate technology); (6) decentralization of policy and economy at all levels, and the formation of communities small enough to be reasonably self-regulating and self supporting; and (7) education for such communities." (13)

To the extent that the costs of pollution associated with production and consumption of energy are not adequately reflected in the prices paid for such energy, utilization of energy resources has been inefficient. Inclusion of costs of pollution mitigation as a result of institution and enforcement of pollution standards will cause energy to be used more efficiently in the future. Such higher prices will reduce the demand for energy below the levels that would be reached if pollution costs were not reflected in the energy prices, providing the demand for energy is significantly elastic.

If the demand for petroleum were reduced by 1 million barrels per day in 1985, environmental damages to the air associated with the consumption of this much oil would be avoided. For example, the following table provides estimated quantities of air polluting emissions from mobile equipment for 1985 (14).

Estimated Emissions from Mobile Equipment
(millions of tons per year)
1985

	Autos	Trucks & Buses	Aircraft	Off-highway	Total
Hydrocarbon	0.9	1.4	0.1	0.5	2.9
Carbon Monoxide	12.7	14.2	.8	3.4	31.1
Nitrogen Oxide	1.3	1.7	.09	1.1	4.2
Particulate	.1	.2	.05	.1	.5

With crude oil demand estimated to reach a minimum of 20 million barrels per day by 1980 and a transportation use of 10-12 million barrels per day (15) a 1-million-barrel-per-day reduction would represent a 7.3-8.5 percent reduction in use in mobile equipment. This reduction in demand presumably would result in an equivalent reduction from the air polluting emissions from the mobile equipment as estimated above.

Another major air pollutant, SO_2, is emitted from stationary plants; the following table shows estimated quantities of SO_2 emissions which are projected to occur in 1980 from plants burning petroleum and coal and from plants smelting copper, lead, and zinc. These estimates are based on the assumption that the same air pollution standards will be in effect in 1985 as were in effect in 1965. Thus, the quantities of SO_2 emission are likely to be considerably overestimated if the technology necessary to meet more recent standards is developed.

Projected SO_2 Emissions from Stationary Plants, 1985 1/
(million tons per year)

Coal	106
Petroleum	81
Smelting copper	28
Lead	4.3
Zinc	3.5
Total	222.8

1/ Interpolated from the figures in the source table for 1985 and 1990.
Source: Reference 14, p. 326.

From the above, a reduction of 1 million barrels per day would be equivalent to a 20 percent reduction in petroleum used for stationary plants and would reduce SO_2 emissions by 12.5 million tons in 1980.

However, the 1-million-barrel-per-day reduction in demand could only reduce either auto emissions <u>or</u> stationary plant emissions, or some combination, depending on where the reduction occurs.

Another major consideration in restricting demand for energy services is that the cost involved in such a restriction is not related to the environmental damage which would be prevented by not producing, transporting and consuming the energy resources involved. In the case where pollution standards are introduced and enforced, causing the amount of environmental damage to the air per unit of energy produced to decrease radically over the period of a few years, the environmental benefits of the action decline but the associated costs do not. Assume, for example, that energy demand is reduced by the energy equivalent of 1 million barrels of crude oil per day, and this reduction is to be accomplished through a reduction in petroleum use in mobile equipment.

The following table shows the trend in quantities of air pollutants estimated to be emitted from mobile equipment using petroleum products (14).

Estimated Emissions From Mobile Equipment
(millions of tons per year)

	1970	1975	1980	1985
Hydrocarbons				
Autos	11.0	5.9	2.4	0.9
Trucks & buses	1.9	1.7	1.4	1.4
Aircraft	.3	.2	.1	.1
Off-highway	.6	.6	.6	.5
Total	13.8	8.4	4.5	2.9

Estimated Emissions From Mobile Equipment (cont.)
(millions of tons per year)

	1970	1975	1980	1985
Carbon Monoxide				
Autos	54.3	40.6	24.3	12.7
Trucks & buses	17.4	16.2	14.0	14.2
Aircraft	.4	.5	.7	.8
Off-highway	5.3	5.5	4.4	3.4
Total	77.4	62.8	43.3	31.1
Nitrogen Oxide				
Autos	5.7	5.0	2.8	1.3
Trucks & buses	1.4	1.6	1.5	1.7
Aircraft	.05	.06	.08	.09
Off-highway	.9	.9	1.1	1.1
Total	8.1	7.6	5.5	4.2
Particulates				
Autos	.3	.3	.2	.1
Trucks & buses	.2	.2	.2	.2
Aircraft	.04	.04	.04	.05
Off-highway	.2	.2	.2	.1
Total	.7	.7	.6	.5

The impact of the stricter air pollution standards is quite apparent from the data above. Interpretation of these data is more complex.

Ideally, the attainment of these standards would be acheived through a combination of methods that will attain the standards and minimize costs. Alternative methods include both hardware development for vehicle emmission control and non-technical solutions that would decrease demand.

Since the cost per unit of pollution that is removed increase exponentially by the application of control hardware, the cost to remove the last unit of pollution to attain the 1985 standards will be significantly higher than the cost required to remove the first pollution unit (in 1970). In addition, hardware pollution controls increase energy consumption (less miles per gallon).

From the foregoing, it may be concluded that an equal reduction in energy demand in 1970 and in 1985 would be <u>more</u> costly in 1985 in terms of energy sacrificed per unit of pollution avoided. However, it may be cheaper to remove the last pollution units through a decrease in demand rather than through the application of control hardware. Such a demand reduction over the short-term would also conserve supplies of depletable energy resources. The benefits and costs of reduced energy use is complex and will depend upon where the reduction is to occur and the level and method of meeting pollution standards. All of these will be reflected in the relative prices of alternative enerby fuels.

There is little evidence concerning the price elasticity of energy demand. In some applications, notably in automobiles, demand may be quite inelastic (i.e., higher prices would have little effect on demand). Gasoline and lubricating oils represent only 25 percent of the total per-mile cost of automobiles (16); thus a 4 percent rise in oil prices would raise total automobile costs only 1 percent. Given the substantial capital investments in automobiles and other energy-consuming facilities, there may be considerable reluctance to incur costs of replacement with lower-consumption equivalents.

Another way to reduce the use of primary energy in the economy is to use energy more efficiently in providing the services demanded. The costs of such measures cannot be estimated, as there is no information on the tradeoffs between energy costs and the additional costs incurred in causing more efficient use of energy. As indicated above, the minimum petroleum and energy demand estimates include increased efficiency in use to the extent it is expected to occur through the operation of current policies and economic adjustments.

Such trends could be increased by government regulations and education efforts. Increasingly, the private sector and the government are seeking ways to conserve energy.

2. Increased Oil Imports

Increased oil imports as an alternative to shale-oil supplementation of crude petroleum must consider the projected production of 1 million BPD of shale oil by 1985 expected from oil-shale development. The alternative of increased oil imports can be accomplished by employing one of two approaches. The effectiveness of any of these approaches would, of course, depend on the continued availability of foreign oil supplies. First, oil imports can be increased in almost any quantity and manner within the context of the Mandatory Oil Import Program and an increase of 1 million BPD can be handled within the existing framework. Second, all oil import restrictions could be removed which would allow foreign imports to enter the United States to whatever extent market systems accommodate the use of such oil in view of domestic production.

a. Mandatory Oil Import Program

Imports of crude oil, unfinished oil, and oil products are controlled under the Mandatory Oil Import Program established in 1959 by Presidential Proclamation 3279 (17). The statutory foundation for Presidential action started with Section 2 of the Trade Agreements Extension Act of 1954 which prohibited any decrease in duty on any article if such reduction would threaten domestic production needed for national defense. Section 7 of the Trade Agreements Extension Act of 1955 added a sub-section (b) which authorized the President to restrict imports found to be threatening to impair the national security. It established a two-step procedure: an opinion by the Director of the Office of Defense Mobilization (now Office of Emergency Preparedness) as to whether imports of a particular article are threatening to impair the national security, followed by a determination by the President

of both the relevant facts and of the action he deems necessary to counteract the threat. The statute was further amended by Section 8 of the 1958 Extension Act in several important respects: (1) to require the President to take remedial action upon a report by the OEP Director, "unless the President determines that the article is not being imported" in a manner threatening the national security, (2) to authorize the President "to take such action, and for such time, as he deems necessary" to adjust imports for the purpose, and (3) to set forth in a new subsection (c) certain standards to be considered; chiefly the impact of imports on "domestic production needed for projected national defense requirements" and on the "capacity of the U.S. to meet national security requirements," as well as the "impact of foreign competition on the economic welfare of individual domestic industries" so as to determine "whether such weakening of our internal economy may (itself) impair the national security." As so amended, the statutory provisions were incorporated without substantive change into the Trade Expansion Act of 1962 as Section 232.

The stated purpose of the Oil Import Program is to protect the national security by restricting imports from foreign sources, thus insuring a stable, healthy industry in the United States capable of exploring for and developing new hemisphere reserves to replace those being depleted.

The limiting of imports of oil into the United States basically is a problem of balancing a sufficient level of imports with domestic production without depressing or eliminating domestic crude oil exploration, development, and production efforts. It generally is agreed that, were the oil import program to be substantially relaxed or abolished, imports presumably would increase, the domestic price of oil over the

short term would fall (perhaps to the price of imported oil if controls were abandoned entirely), short-term foreign crude prices might rise, and marginal domestic production would be forced out of production. Further, domestic exploration and development incentives would be reduced resulting in a decline in the development of new domestic oil and gas resources.

b. <u>Present Operation of the Oil Import Program</u>

On February 20, 1970, the President established the present Oil Import Policy Committee. In his release he stated:

> "While most day-to-day administrative functions will continue to be performed by the Oil Import Administration (now Office of Oil and Gas) of the Department of the Interior, the policy, direction, coordination, and surveillance of the program will be provided by the Director of the Office of Emergency Preparedness, acting with the advice of this permanent Oil Policy Committee."

The Committee is composed of the Director of the Office of Emergency Preparedness (Chairman), the Secretaries of State, Treasury, Defense, Interior, and Commerce, the Attorney General and the Chairman of the Council of Economic Advisors. The Chairman of the Oil Policy Committee makes his oil import recommendations to the President. Upon acceptance, the President then issues such policy in the form of a proclamation. Oil Import Regulations are promulgated by the Secretary of the Interior with the concurrence of the Director, Office of Emergency Preparedness.

Presidential Proclamation 3279 (17), as amended, restricts petroleum imports into the United States by product (commodity), geographical area in the United States and, in some instances, country of origin.

Allocations of imports of crude oil, unfinished oils, or finished products are made for a period of 1 year--that is, January 1 through December 31, except that allocations of imports into Petroleum Administration for Defense (PAD) District I of residual fuel oil to be used as fuel and allocations of crude and unfinished oils in Puerto Rico are

made on an annual basis beginning April 1.

Prior to the beginning of each allocation period, the Administrator of the Oil Import Administration determines the quantities of imports of crude oil, unfinished oil, and finished products which are available for allocation in Districts I through IV, District V, and in Puerto Rico respectively. He also determines the quantities of imports of residual fuel oil to be used as fuel in Districts I and V. The Secretary of the Interior may review the level of imports of residual fuel oil to be used, making such adjustments as he determines to be consonant with the objectives of the proclamation.

Applications for allocations of imports of crude oil, unfinished oils, or finished products and for a license or licenses must be filed with the Director, Office of Oil and Gas not later than 60 calendar days prior to the beginning of the allocation period for which the allocation is required. Allocations of crude oil and unfinished oils are made to petrochemical firms and to oil refiners. Refinery allocations are made relative to the refinery inputs of the prior 12-month period ending September 30. A sliding scale is used to give preference to small refiners.

Allocations and levels for the importation of petroleum are published annually for Petroleum Administration Districts I-IV (States East of the Rocky Mountains), District V (West Coast States, plus Alaska and Hawaii) and Puerto Rico. For purposes of import controls, petroleum imports are generally categorized as crude, unfinished oils, finished products, No. 2 fuel oil, asphalt, and residual fuel oil.

Product imports are almost negligible, except for the importation of 45,000 B/D of No. 2 fuel oil and unrestricted but licensed quantities of residual fuel from overseas sources into District I (the East Coast

States plus Vermont and West Virginia), asphalt into District I-IV, and finished products manufactured from Canadian crude and imported over-land from Canada into Districts I-IV. Imports of other products such as gasoline have been intentionally discouraged to minimize the "exportation" of refining capacity.

Special arrangements are made for imports into Puerto Rico, and for shipments of relatively small quantities of products from Puerto Rico (64,000 barrels per day) and imports from the Virgin Islands (15,000 barrels per day) to the mainland.

Imported unfinished oils (15 percent of the license in Districts I-IV and 25 percent in District V), as well as crude imports are further processed upon entry into the U.S. These oils are imported primarily by refiners, although some licenses are granted to petrochemical producers.

Allocations to refiners are made according to a sliding scale based on refinery inputs. Petrochemical allocations are computed as a percentage of inputs. (11.2 percent in Districts I-IV and 11.9 percent in District V).

The level for imports into District V is computed as the amount required to supplement shipments from other PAD Districts, estimated domestic crude production, and overland imports from Canada so as to meet estimated demand in District V. The level for imports into Districts I-IV other than residual fuel and certain products which enter without restriction (Canadian NGL, Western Hemisphere LPG), was calculated as a percentage of estimated domestic consumption during the early years of the Mandatory Oil Import Program. At the present time, the quota is computed as 12.2 percent of estimated domestic production in Districts I-IV, plus annual increments of the magnitude

recommended by the minority Report of the Cabinet Task Force on Oil Import Control. Although the modified 12.2 percent formula remains the official basis for computing the quota, the annual increment is now based on a comparison of projected supply and demand. On May 11, 1972, the President issued a proclamation raising oil import quotas in Districts I-IV by 230,000 barrels a day. The Canadian quota was raised 30,000 barrels per day while the offshore quota was raised by 200,000 barrels. This represents an overall increase of about 15 percent. The quota for Districts I-IV may be allowed to expand further as increases in demand continues to outstrip domestic production capacity.

c. International Uncertainties

In considering the modification or elimination of the Mandatory Oil Import Program as an alternative to 1 million BPD of shale oil, a particular concern is the security of Middle East supply sources which have been characterized by instability and international tension. The supplies of oil from that area may be subject to interruption for political or economic reasons with little or no advance warning. In their comments relative to the Department of the Interior's Analysis of the Economic and Security Aspects of the Trans-Alaska Pipeline (15), the Secretaries of State and Defense and the Director of the Office of Emergency Preparedness indicated their concern that "failure

to obtain desired additional oil supplies (from the North Slope) will necessitate increasing imports from insecure sources to such high levels that a long-term foreign supply distribution could slow down industry and imperil our national security." Failure to bring shale oil into production would raise dependence on imported oil from a range of from 33 to 41 percent to a range of from 37 to 45 percent in 1985.

A systematic treatment of the oil import subject is contained in the report of the Cabinet Task Force on Oil Import Control (18). The majority of the task force concurred that no more than 10 percent of U.S. requirements should be met by imports from the Eastern Hemisphere. Such a limitation would require some type of continuing import controls.[1/]

Eight major difficulties that might attend dependence on foreign supplies were identified by the Cabinet Task Force (18):

"(1) War might possibly increase our petroleum requirements beyond the ability or willingness of foreign sources to supply us.

(2) In a prolonged conventional war, the enemy might sink the tankers needed to import oil or to carry it to market from domestic production sources such as Alaska.

(3) Local or regional revolution, hostilities, or guerilla activities might physically interrupt foreign production or transportation.

(4) Exporting countries might be taken over by radical governments unwilling to do business with us or our allies.

(5) Communist countries might induce exporting countries to deny their oil to the West.

(6) A group of exporting countries might act in concert to deny their oil to us, as occurred briefly in the wake of the 1967 Arab-Israeli war.

1/ A subcommittee of the House Committee on Interior and Insular Affairs held extensive hearings on the Task Force report. See U.S., Congress, House, Committee on Interior and Insular Affairs, Oil Import Controls Hearings, before the subcommittee on Mines and Mining, March and April 1970.

(7) Exporting countries might take over the assets of American or European companies.

(8) Exporting countries might form an effective cartel raising oil prices substantially."

A subsequent study made by the Petroleum Industry Research Foundation reexamined the principal assumptions and conclusions of the Task Force regarding U.S. dependency on oil imports in 1980 under various price assumptions (-). This study raised further questions as to the extent to which the United States should depend on Middle Eastern and North American petroleum sources.

A Joint Economic Committee Background Study relative to the April 15, 1971, OEP Report on price increases in crude oil and gasoline raised numerous questions relative to the need for, and effectiveness of, the Mandatory Oil Import Program (-).

The security problems has two principal parts: a question of military security, and a question of economic security. Both advocates and critics of the Oil Import Program have tended to focus principally on the economic security issue.

The crux of the argument against importing a substantial fraction of the nation's oil is that the source of additional foreign oil; in general, the Middle East and North Africa are "insecure," and they might be tempted to withhold oil exports to the United States for political and/or economic gain (generally in an environment short of war, though local conflicts in volatile areas are not inconceivable).

A study by Drs. Schurr and Homan for Resources for the Future (19) notes that the question of supply interruptions

"...needs to be dealt with in the interests of both the importing and exporting countries because supply interruptions are economically damaging to both. Not only do they have sharp short-run effects which are economically painful, but their long-run consequences can also be damaging if channels of commerce are diverted into

alternatives which impose a permanent economic penalty upon both those countries that well oil and those that buy."

However, this interdependence does not guarantee that interruptions will not occur. The study points to interruptions from the shutdown of Iranian production beginning in 1951, the closure of the Suez Canal and attendant lengthening of transportation routes in 1956-1957 and again from 1967 to the present, and quotes Walter Levy, a leading international oil authority and consultant, as saying:

> "Nor can the West rely on the importance of uninterrupted oil operations and oil revenues to Middle East governments as a deterrent to hostile actions. Economic considerations, important as they are to the relatively impoverished countries of the area, become insignificant when confronted with political necessities or political pretentions."

Eleven major oil-producing countries have joined the Organization of Petroleum Exporting Countries (OPEC) in an attempt to obtain greater bargaining power in their dealings with the international oil companies. A 5-year agreement reached in 1971 with the Persian Gulf countries provides for substantial increases in the payments to the host governments. The other members followed with equal or larger increases. In the second year of the agreement, the OPEC countries have been given further increases to compensate for the de-valuation of the dollar. They also seek participation as part owners in the oil companies exploiting their resources. If OPEC can maintain cohesiveness in the face of diverse national demands and historical relationships, continuing pressure for economic and political concessions by the oil-importing countries may be anticipated.

d. <u>Potential Environmental Impact of the Alternative</u>

Increasing imports in lieu of shale oil production would affect

the environment through: (1) Provisions needed to protect the national security from interruption of oil supplies and (1) the additional oil handling associated with the vessels and related facilities required to transport and handle additional imports.

Security measures which do not require pre-crises investment (draw-down, rationing, etc.) would have little environmental impact. Storage in steel tanks or in cavities created in salt domes would require importing oil for the inventory in addition to that for current demand, with associated tanker risks discussed below. Storage of 1 million barrels of oil in steel tanks would require approximately 25 acres (assuming a 16-foot high dike is used to protect against accidental spills) and the danger of leakage would increase as tanks age. Storage in cavities in salt domes would remove the requirement for above-ground tank; however, pipelines, injection, and extraction facilities would still be required. Also, it might be anticipated that due to the attraction of the oil to the mineral matrix, less than 100 percent of the oil injected into cavities in salt domes can be extracted. Quantities in excess of the desired emergency supply would have to be imported and a portion of this would be unrecoverable. Salt removed from the salt cavities during oil extraction, if not handled properly, could be a source of pollution through leaching of the salt by water.

Development of spare shut-in capacity in the Naval Petroleum Reserves, on other lands purchased by the Federal Government, or through a Federal prorationing system would entail environmental impacts similar to those associated with exploration and development both on- and off-shore (described in a subsequent section of this

analysis). Potential production at Elk Hills is not equal to those from the proposed oil-shale development, so that development of shut-in capacity at Elk Hills alone would not suffice.

The environmental impacts of increased imports arise from three sources: (1) Increases ship traffic to the subject ports, (2) the construction and operation of increased capacity of terminals for the receipt of the oil, and (3) the transportation of the oil from off-shore terminals to coastal refineries.

The worldwide tanker casualty analysis indicates that 0.0192 percent of the oil transported is spilled, exclusive of transfer operations. Applied to the 1,000,000-barrel-per-day throughput, this amounts to approximately 192 barrels per day discharged from casualties. However, it must be recognized that an average calculation such as this has little meaning from an environmental impact standpoint. Such impacts could be nominal where small spills are involved or where the spill occurs in such a manner as to have little impact on coastal or restricted water areas. By contrast, a single catastrophic incident can have disastrous results. A recent study (20) showed that 75 percent of past major spills were associated with vessels (Figure 11). Further, the source of spills of more than 2,000 bbl was likely to be a tanker, and the spill would occur within a few miles of shore and be noticeable for more than five days. Shorelines threatened would be at least partially recreational with a reasonable chance that only light coastal contamination would occur (21).

The oil-spill problem is a subject involving considerable study effort. The first report of the President's Panel on Oil Spills presents considerable detail relative to this subject (22).

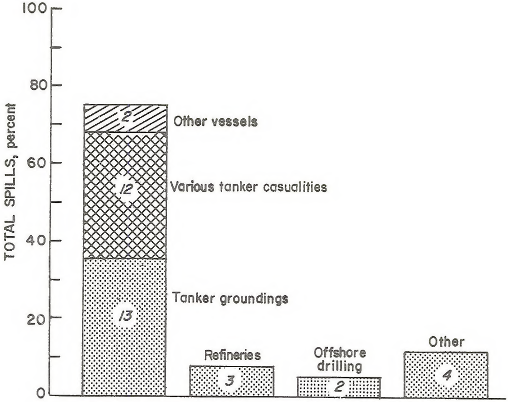

Figure 11 . —Source of spill (Data from 36 incidents).

Source: National Petroleum Council, Environmental Conservation, v. 2, February 1972, p. 242.

3. Modification of Market-Demand Prorationing Systems

The objective of this alternative would be to obtain increased production from developed reserves that are being produced at less than maximum efficient rates. The alternative would require those states operating prorationing systems to revise their laws and regulations to permit such full production. This cannot be considered as an alternative to projected supplies from shale oil because declining crude oil productive capacity and increasing demand for crude oil will require production at maximum efficient rates (MER) (23 to 25).

Elimination of state market-demand prorationing would result in very little additional crude oil and natural gas production. Important exceptions to MER production currently remain only in the Elk Hills Naval Petroleum Reserve (which is not subject to state market-demand prorationing and which will be discussed in a later section of the statement) and a small number of fields in Texas and Louisiana. Louisiana officials are reviewing producing potentials on a field-day field basis, and indicate that the state will be producing at MER by early fall 1972.

Only three Texas fields, East Texas, Kelly-Synder and Tom O'Connor are to be restricted below 100 percent of their respective market-demand factors as of September 1972. Conservation problems encountered at higher operating rates have compelled reduced production in these fields while unresolved issues of correlative rights to the crude oil also preclude higher production from East Texas. A very few Texas fields have MER's in excess of 100 percent of their market demand factors and of these the largest, Yates, also has unresolved problems of correlative rights. Projections of United States petroleum production and requirements indicate that remaining potentials and newly

developed capacity will be put into production as consideration of conservation, environmental protection and equity permit and the issue of market-demand prorationing will remain moot.

4. Modification of FPC Natural Gas Pricing

This alternative postulates increases in prices for natural gas to provide additional incentives to natural gas producers to increase natural gas exploration and development. Some additional crude oil would probably be discovered as a result of increased exploration for gas. Also, some crude oil demand would be displaced by incremental natural gas supplies. Since natural gas is a clean fuel as compared to oil, this displacement would result in a net environmental benefit. However, it is not considered to be substitution that could be utilized to totally offset (a major portion of) shale-oil supplies.

In 1954, the Supreme Court ruled that producers of natural gas for sale in interstate commerce are subject to regulation under the Natural Gas Act. Since then sales, including pricing, of gas destined for interstate markets has been subject to Federal regulations as administered by the Federal Power Commission (FPC).

The FPC changed its method of price regulations in 1960 from an individual company "cost-of-service" method to an "area rate" concept which was upheld by the Supreme Court. Under the area rate method, average unit costs associated with all aspects of natural gas production are determined for a producing area instead of examining the costs of each producing company.

Concern has been voiced that interstate gas prices resulting from FPC actions have been so low as to retard development of new gas supplies while at the same time, inducing associated consumer preferences for gas over alternative fuels. (26)

Recognizing the need for new policy initiatives, the FPC has, within the past 2 years, taken a number of measures designed to increase gas supplies, including increased price ceilings (27). FPC raised rate ceilings by about 35 percent during 1968-70 and on July 16, 1971, in its Opinion No. 598, set new, higher ceiling rates for the South Louisiana area and provided for a system of incentives to promote dedication of gas reserves to the interstate market.

To provide additional incentives, the Federal Power Commission issued Order No. 455 on August 3, 1972, which provides an optional procedure for certificating new producer sales of natural gas. This new order does not replace geographical area pricing, but rather will provide, if upheld by the courts, an alternative procedure for certification of sales for new gas at rates above established area ceilings. It is intended to stimulate and accelerate domestic exploration and development of the nation's natural gas reserves so as to assure interstate gas consumers, and the nation as a whole, an adequate and reliable supply of natural gas at the lowest reasonable cost.

Alternative sources of gas, such as liquefied natural gas imports and the production of synthetic natural gas involve costs for higher than current regulated interstate prices of natural gas. It may be likely therefore, that recent FPC actions to permit higher wellhead gas prices will be followed by still other steps in this direction.

Estimated United States resources of oil and gas as yet undiscovered are sufficiently large to support an expanding rate of domestic production through 1985 and beyond. Recent levels of domestic exploration and development, however, have not been sufficient to prevent a decline in the Nation's proved reserves of both gas and oil.

Improved economic incentives, whether in the form of higher prices or other wise, would most probably increase investment in stimulated recovery of known but not now recoverable oil resources and would induce a higher rate of exploration for gas and oil. However, the relationship between economic incentives and the level of expenditures for exploration cannot now be uniquely identified; even greater speculation must be attached to the degree of success in finding commercially viable oil and gas fields at any level of exploratory activity.

A listing of specific environmental impacts is not included in this section because any results of the proposed alternative can be directly attributed to other alternatives. Discussions of the environmental impact of increased production from on-shore and off-shore areas are applicable to this proposed action as discussed elsewhere in this volume.

C. Alternative Energy Sources

1. Increased Domestic Production of Petroleum

Discussion of additional domestic production of crude petroleum (and natural gas) must consider production from onshore and also from the continental shelf. Additional domestic production from either of these sources above is not a viable alternative to the projection shale-oil production for reasons which are detailed in the discussion that follows:

a. Offshore Production

This alternative would require increased exploration, development and production of crude oil from offshore areas. Supplies equal to all, or a significant part, of the projected 1 million barrels daily from the shale oil would have to be developed and produced in addition to those supplies that are projected to be produced from offshore sources during the same time frame.

Evaluations of discoveries in offshore areas indicate that a drilling effort in excess of 6,000 wells might be required to provide supplies similar to those that could be provided through the shale oil program between 1976-1980. These wells would be in addition to those that are expected to be drilled to provide supplies to meet projected offshore demands during the same time frame. In 1970, 1,063 offshore wells were drilled. If this alternative were to be effective, drilling efforts would have to be doubled.

Changes that could be beneficial to stimulation of additional development include price increases, subsidies, tax benefits, and changes in leasing procedures. The cost and effectiveness of such changes are unknown. The timeliness and the volumes of increased supplies that would result from increased incentives are also unknown. Drilling rig availability would be a major problem. Less than 100 rotary rigs were operating in domestic offshore waters in 1970.

Currently, there are 1,005 leases, comprising 4,261,661 acres. Six hundred of these leases, more than 2.5 million acres, have been proved productive. In order to accelerate the OCS leasing and production as an alternative to shale oil from 1.8-3.6 million acres would have to be leased during FY 1972-76, assuming productivity comparable to the recently proposed eastern Louisiana offshore sale. A minimum of approximately 1,500 miles of pipelines would have to be put into operation in the Gulf of Mexico. If leasing were to occur in virgin OCS areas, such as the Atlantic and the Gulf of Alaska, pipeline requirements would be much greater.

Even though there is a demonstrated need for development of petroleum resources in offshore areas, development has not progressed to the extent required to meet projected production requirements. In response to the

President's June 4, 1971, Clean Energy Message, which called for accelerated OCS leasing, tentative schedule for leasing oil and gas resources on the OCS setting forth sales through 1975 was published. The schedule proposed an average of two major sales per year, double the previous rate. Both traditional OCS leasing areas in the Gulf of Mexico and virgin areas such as the Atlantic and Alaska OCS are included.

Implementation of the schedule has been delayed by a court injunction which precluded the completion of the December 1971 general lease sale offshore eastern Louisiana. Although no commitment to hold a sale off the Atlantic Coast has been made, opposition to such a sale already has been voiced.

(1) Potential Environmental Impacts. - The potential environmental impacts that are encountered from continental shelf leasing and production include impacts on air and water quality, and impacts of structures, waste water, oil spills, health and safety, and other aspects such as mitigating restraints concerning OCS mineral leasing. Anticipated environmental impacts from OCS are covered in detail in a final environmental statement issued by the Bureau of Land Management, U.S. Department of the Interior (28).

(a) Air and Water. - The initial effort in OCS exploration involves geophysical exploration activity. Exploratory seismological surveys leave little lasting impact. The principal effect of such activity is similar to the impact of surface use for commercial and sport boating on the marine environment. Deisel powered vessels used

for seismic surveys and drilling rig engines create noise and emit exhausts which can pollute the air. Whereas vessels use water courses and harbors in proximity to populated areas, they may have a minor direct effect on the coastal area environment. The improper disposal of trash, debris, bilge wastes, and spills of crank case oil and engine fuel characterize other kinds of pollution attributable to seismic vessels and the vast array of crew boats, service vessels, tugs and drilling rigs which operate in the offshore area. Inasmuch as drilling rigs occupy a single location for an extended period of time, the duration and the seriousness of the form of pollution in the immediate vicinity of the drilling rigs depend on the magnitude of such pollution and such other characteristics as surface winds, tides, currents, bottom scouring and water temperature, which tend to concentrate, dilute through dissipation, and transport pollutants elsewhere.

The greatest potential for serious pollution of offshore waters by hydrocarbons during drilling operations is from a blowout. Normally, drilling muds and blowout prevention devices control the natural pressure in a well.

Nevertheless, blowouts do occur which result in the release of oil from the wellbore. Most blowouts occur in gas wells; oil blowouts are relatively rare, but they have occurred. However, hydrocarbon fluids are associated with natural gas, so the seriousness of gas well

blowouts depends on the amount of fluids produced with the natural gas (on the average, about 30 barrels of liquids are produced per million cubic feet of natural gas).

(b) Structures. - The construction of offshore drilling platforms generally causes temporary turbidity of the water during the construction operation and can damage aquatic life. Such turgidity is associated with the construction phase of the operation, so it is temporary in nature and impact. It is possible to avoid substantial impact upon aquatic life on the floor by locating platforms away from significant ecological areas. Platform spacing can minimize their adverse effect upon commercial fishing operations. New control technology and procedures make it pollible to minimize the potential for oil leakage associated with the production operation.

There are over 14,000 offshore wells in the offshore areas; 9,000 are located in the Federally administered Outer Continental Shelf. The structures serve as drilling platforms, production and treating platforms and labor force living quarters. The geographic density of such units on Federal OCS areas vary considerably and generally most are three or more miles from shore so they are out of sight of land. Platforms and drilling rigs in view of land may disturb the scenic views and vistas of the coastal inhabitants and the open space qualities of the seascape.

Offshore platforms can pose navigational hazards but also can aid navigation. They also serve as artificial reefs which attract fish, which in turn attract recreation fishermen and boaters. These qualities can become tenuous if fish catches become tainted by petroleum and boats are stained by oil. The noise of drilling rigs, acoustical warning devices, and support vessel traffic operating in rivers and canals can be objectionable to residents living along the coast and waterways as well as to pleasure craft also using such water courses.

(c) Transportation. - Pipelines laid offshore are buried to avoid the danger of being struck or dragged by ship anchors as well as to avoid movement in the event of strong water currents in times of intense storms, such as hurricanes. Approximately 98 percent of oil and natural gas produced offshore is transported to shore by pipeline. Although well blowouts attract the most attention, spillage of oil due to the rupture of pipelines which transport offshore production to shore terminals can be serious. It is estimated that during the last decade ruptured pipelines caused more pollution than drilling and production operations. Approximately 2 percent of offshore oil is transported to shore by barges. Pipeline construction in marsh areas resulting from OCS operations could contribute to marsh destruction. The adverse effects may be either short-term or permanent, and may be minor or serious, depending on the methods employed in laying pipelines and their location. These effects can be substantially reduced with

adequate planning and by using the most appropriate construction techniques. For example, pipeline corridors or existing pipeline canals should be used whenever possible so that adverse impacts are restricted to fewer locations. Where possible, pipelines should come ashore on elevated terrain to minimize damage to marshlands. Usually bulkheads are placed in canals to prevent saltwater intrusion and to maintain existing drainage and water-exchange routes. To protect oysters, pipelines are usually routed around major oyster reefs, and where shallow estuaries are to be crossed, the canal is usually backfilled; in many cases so are canals through marshlands.

(Oil spillage can occur during loading periods, in transit, and when bottoms are cleaned). During the past 10 years, over one-third of a million barrels of oil have been spilled into the sea due to significant offshore accidents related to oil and gas operations.

The effects of oil spills are discussed later in a section concerning coastal areas.

(d) Waste Water. - A production element which contributes to offshore pollution is the disposal of waste water associated with oil production. Although the volume of such waste discharge is relatively small, an increase in offshore oil activity, and the advancing state of depletion of water drive fields will cause waste of this kind to be an important consideration. The seriousness of waste water as a pollutant is aggravated by oil and chemicals, used to enhance the separation of

oil and water, entrained in such waste. The oil content of waste water discharged in the OCS operations is limited to 50 ppm under OCS Order No. 8. Although much research effort has been made, the effect of waste water and traces of chemicals in the seawater upon flora and fauna is not fully understood.

Appropriate early planning and adequate consultation with State, local authorities and with industry can assure the protection of areas which are significant natural habitats to important species of fish or animal life.

The potential for oil spills could continue to grow as offshore production increases to meet growing demand.

(e) Biological Conditions. - Construction of drilling platforms and laying pipelines generally disturb benthonic organisms and creat turbidity which has a minimal period of small ecological effect on the bottom. Construction of platform and pipelines also has the potential for damaging marine life located in offshore areas. Pollution created by dumping of trash, small oil leaks, etc., may have a localized ecological impact. The real short or long term impacts of such minor pollution is unknown.

Since the advent of the offshore oil and gas activities many species of fin fish have become concentrated around the drilling structures, which obviously provide attractive habit conditions. Among these are: red snappers, groupers, trigger fish, spade fish, giant sea bass, pompano, and many smaller species. There has been speculation that these species and other larger seasonal game fish, such as sail and bill fish, have appeared since the offshore oil industry became active. The platforms create unique offshore artificial environments which attract and concentrate many predatory species, providing favorable fishing sites for sportsmen and commercial snapper fishermen. The long term effects of this intense species concentration, in lieu of the more random distribution patterns, is not known; but natural predator-prey relationships could be affected.

(f) Coastal Area and Land Environment. - The environment of the near shore and coastal land areas could be adversely affected by increased offshore production. The area is of specific importance because people and industry are both concentrated in the coastal zone. The coastal counties of the U.S. have 15 percent of the land area, 33 percent of the population, and 40 percent of the manufacturing plants.

Data compiled from the Pollution Incident Reporting System (PIRS) of the U.S. Coast Guard show that in 1970 there were 12 spills attributed to offshore oil wells. Total quantity of oil involved was estimated to be 111,900 bbl. When related to the 589,127,000 bbl of oil produced in offshore areas, spills attributed to offshore production are extremely small (.0002 percent). There were 23 spills attributed to offshore pipelines with only one of significant size. Twenty-two spills were estimated to average 5 bbl per spill. A total of 295 spills were attributed to barges. Average size of the spill was estimated at approximately 66 barrels per spill.

Marine birds, especially diving birds, appear to be the most vulnerable of the living resources to the effects of oil spillage. Harm to the birds from contact with oil is reported to be the result of a breaking down of the natural insulating oils and waxes shielding the birds from water with the consequent loss of body heat. The 1969 Santa Barbara oil spill resulted in the recorded death of 3,686 birds and some marine organisms at the waterline.

Efforts to cleanse or rehabilitate contaminated birds have generally been unsuccessful. Less than 20 percent of the treated birds survived the Santa Barbara clean-up attempts.

The effects of oil spillage on the marine food chain or food web (which consists of plants, bacteria and small marine organisms) are not well understood because of the wide fluctuations and cycles that occur naturally and are totally independent of the effects of oil (29).

A ditching or jetting operation associated with construction on offshore areas generally causes temporary turbidity of the water in the

immediate vicinity and may drive away fish and other aquatic life during that time. It is possible that the operation may also damage a portion of any shell fisheries existing in the immediate area.

(g) Oil Spill Recovery, Containment, and Dispersement.- Equipment and procedures for recovering oil spill in protected waters are well developed, but similar capability in the open sea is limited. There are no recovery devices capable of picking up oil in rough seas. The use of sorbents which have an affinity for oil pose specific problems: distributing sorbent over the area affected by the oil spill is difficult particularly in high winds; there is no effective procedure for collecting the sorbent after contact with spills, and treating or disposal of such oil-saturated materials is difficult. The chemical and physical process and potential impacts of sinking oil to the ocean bottom is dubious practice. Most ecologists agree that sunken oil is particularly undesirable in shell fish-producing intertidal areas. The use of dispersants on spills introduces the problem of toxicity of such materials if they are poorly handled or are not properly diluted in the water column (29).

Marine life may also be affected by efforts to remove the surface oil. Emulsifiers, as well as natural storm action, remove oil from the surface by redistributing it as minute droplets throughout the water column. In this condition, oil is more susceptible to biological and chemical degradation, although in combination with such chemicals, it also usually is more toxic. Furthermore, the oil treating chemicals themselves have been found to be more toxic than crude oil in many instances (30).

"Shellfish appear to be quite vulnerable to the majority of chemical dispersants, and in past oil-spill incidents where heavy dispersant spraying has been conducted in the tidal zone or in shallow areas with restricted circulation, large shellfish kills resulted. Fortunately, the effects of oil spillage on shellfish appear to be fairly temporary, and even in those situations where high mortalities were observed at the time of the incident, complete recovery of the shellfish population appears to have taken place within a period of 6 months to 2 years." (29, p. 14.)

The marine environment is rich in both its variety and numbers of marine life. Pollution can affect, in varying degrees, all forms of marine plant and animal life from those that are lowest in the food chain to those at the top. The degree of pollution, duration, and the physical condition under which it occurs determine the extent of the impact. After pollution has occurred, a normal balance may be regained in a short period of time or the impact may be more severe and recovery may require a span of many years. Little is known of what effect the chronic incremental discharge of oil, associated with normal drilling and producing operations, may have on the marine food web.

In any case, the normal "health" of the ecosystems is disrupted and a balance is lost during the period of recovery.

Shorebirds, waterbirds and migratory waterfowl frequently are the most obvious victims of oil pollution because they are likely to come into direct contact with it. Contamination by oil destroys the waterproof qualities of their plumage a condition from which they seldom recover, even when careful rehabilitation is attempted. Similarly, bird species are vulnerable if beaches and marches become contaminated by oil, especially if vegetation and food sources are destroyed. In the northern hemisphere,

hundreds of thousands of swimming and diving birds have perished from oil pollution during and since World War II, and marked reduction of some nesting populations of sea birds from such mortality has been documented (31). However, no such problem has been documented in the Gulf of Mexico as a result of oil spills.

(h) Summary.- Even with the best systems and controls, some oil pollution will occur. The recently strengthened regulations and operating orders[1/] are as stringent as technology allows at this time. Although increased Federal inspection and the large costs involved in controlling, containing, and cleaning up spilled oil have combined to generate an awareness of the necessity to improve the OCS safety record, no regulation or enforcement can guarantee that there will be no pollution from oil producing operations on the OCS. Natural disasters, equipment failure and human error could occur despite regulations and enforcement procedures. Federal standards will do much to widen the margin of safety on OCS operations, but they cannot guarantee there will be no oil spillage.

The marine environment is rich in variety and in the forms of marine life. Pollution can affect, in varying degrees, all forms of marine plant and animal life from those that are lowest in the food chain to those at the top. The degree of pollution determines the duration and extent of the impact. A normal balance may be regained in a short period of time or the impact may be more severe and recovery may require a span of years. The normal "health" of the marine ecosystems in any case is disrupted and a balance is lost during the period of recovery.

1/ National Oil and Hazardous Substances Pollution Contingency Plan, 36 FR 16215, August 20 1971.

Shorebirds, waterbirds, and migratory waterfowl frequently are the most obvious victims of oil pollution because they come into direct contact with it. Oil destroys the waterproof qualities of their plumage from which they seldom recover, even when careful rehabilitation is attempted.

New pipelines required to move new production of oil and gas from producing areas to coastal uplands for processing or redistribution would be buried beneath the ocean floor so post-construction impacts would be minimal. When pipelines are buried in coastal marshes it has been a common practice to dredge canals in which to place them. Such pipeline canals can increase the ratio of water to wetlands by physically removing the coastal marshes, by facilitating drainage of freshwater necessary to maintain diluted conditions in the estuaries, and by increasing the rate of salt water intrusion from the more highly saline coastal waters. The dredging and redepositing of the displaced sediment also can be destructive to aquatic plants and animals. Recent studies (32) indicate that 16.5 square miles of marsh have been destroyed each year in coastal Louisiana by erosion, subsidence, and construction. Most of this destruction is attributable to natural causes, including hurricanes, but some 12 percent to 15 percent is due to canalization accompanying oil and gas pipeline installations and oil rig access channels.

Accordingly, pipeline construction must be so controlled as to avoid serious contributions to further marsh destruction. The adverse effects may be either short-term or permanent, and may be minor or serious, depending on the methods employed in laying pipelines. Insufficient data exists on what effect the incremental discharge of oil will have on the fishery resource and its supporting food web.

A major spill or chronic minor spillage could affect the beaches, water areas and historic sites making them at least temporarily unusable for recreational purposes. If such pollution incidents occurred during periods of normal heavy visitor use, loss of recreational enjoyment and use and the loss in economic benefit to the vicinity cound be substantial.

Water sports, such as swimming, diving, spearfishing, underwater photography, fishing for finfish and shellfish, boating, and water skiing would be most directly affected. Other marine-related activities such as beachcombing, shelling, painting, shoreline nature study, camping, and sunbathing would be made much less attractive for an indeterminate period, depending upon the promptness and efficiency of the cleanup effort.

Despite the installation of navigational aids the erection of additional platforms on the OCS particularly those adjacent to fairways, could pose an increased hazard to shipping.

Safety fairways have been established to permit safe passage of vessel traffic into and out of ports. Anchorage areas are similarly designated for safety purposes. While exploratory drilling in shipping lanes is permitted with approval by the Corps of Engineers, installation of fixed structures is prohibited under 33 U.S.C. 403 and 43 U.S.C.1333(f). Production can be initiated, however, by directional drilling from a portion of the bract outside the lane or from adjacent leaseholds outside of fairways.

It is doubtful that a leasing program could be accelerated to an extent that production additional of one million bbls per day could result with a proper concern for efficient resource recovery and adequate protection of the marine environment within the 1972-85 time frame.

b. Onshore Production

This alternative would require increased exploration, development and production of crude oil (and natural gas) from onshore sources. To be a real alternative, supplies equal to all or a significant part of projected supplies from shale oil would have to be developed in addition to those supplies that are projected to be produced from onshore sources, during the same time frame. Experience indicates that it would be extremely difficult, if not impossible, to expand drilling efforts to provide additional needed supplies, especially when consideration is given to the drilling effort required to offset continuing declines in onshore production. Past discovery rates indicate that the drilling of over 50,000 additional wells might be required to provide equivalent supplies to what could be delivered from oil shale within the proposed time frame. In 1970, less than 30,000 wells were drilled in onshore areas.

Onshore drilling in recent years has continually declined; a major contributor to the decline has been a lack of economic incentive. Additional incentives such as subsidies, price increases and tax benefits could result in increased drilling and development of onshore domestic supplies, but little information is available to evaluate the cost effectiveness of such a program. With increased incentives, additional exploration, development, and production of supplies could be expected but increases in crude oil supplies from new discoveries could not be expected to be forthcoming in significant enough quantities to offset a million barrel per day rate of shale oil production in 1985.

Two hundred forty-six billion barrels of crude oil are estimated to be recoverable from domestic onshore areas, including Alaska North Slope,

under current technological and economic conditions. Potential onshore reserves would be adequate to meet projected requirements but past and current drilling efforts have not resulted in discoveries that would have provided adequate increased production. The most favorable geologic provinces already have been developed so exploration success possibilities are reduced. In the late 1940's only 30 wildcat wells were needed to locate a significant new field; the number of wells required had nearly doubled by 1960 and this trend has not reversed.

The importance of finding large fields becomes apparent when it is noted that last year 63 percent of U.S. production was from only 264 giant fields. There are over 35,000 oil fields in the United States.

Development of spare shut-in capacity in the Naval Petroleum Reserve at Elk Hills in Kern County, California, could be a partial alternative. Production has been limited to about 2,000 barrels of oil per day. In 1970 shut-in capacity was estimated to be about 160,000 BPD. At that time, the expenditure of approximately $100 million for drilling, plants and compressors, and $50 million for additional transportation facilities could result in increased production to about 350,000 barrels of crude oil per day of production (33). Congressional approval would be required for any appreciable increase over the current producing rate.

Technological advances permit improved recovery of oil from existing reservoirs, and, in effect, increase the "recoverable reserves" in a producing formation by a process called "secondary recovery." Further improvements may be expected. However, the existing forecasts usually include provision for some improvements in recovery, often explicitly. For example, The National Petroleum Council projects reserve additions of 28.5 billion barrels, or 71 percent of its 1971-1985 totals, from application of secondary and tertiary recovery processes (34). Much of the production capacity added in recent years has been obtained through such improvements, and further dramatic increases are generally not anticipated at current costs and price levels. Thus the improved recovery case may, in that sense, be considered equivalent to the price-rise case.

Ultimate recovery of oil is currently estimated at 31.1 percent of original oil in place. The applicability of recovery techniques depends strongly on the nature of the oil reservoir; the estimated recovery ranges from 13.5 percent in Ohio to 65 percent in District 6 of Texas. With estimated original oil-in-place of 425 billion barrels, an increase of only one percent in the average recovery of oil in place would yield 4.25 billion barrels, or 2 million barrels per day for 12 years. However, a recent assessment (35) of recovery trends stated that:

"The rate of improvement in recovery efficiency appears to be diminishing rapidly, however. The fact that an average of only one-third of the discovered oil in the ground is being recovered currently, and that significant oil deposits are becoming more difficult to find, emphasizes the need for a continuing research effort in these areas."

(1) Potential Environmental Impacts. - This section discusses environmental impacts involved in current domestic crude petroleum production onshore. These impacts would increase by about 5 percent the total environmental impact that would result from developing production needed to meet projected future demands for crude petroleum.

(a) Air Quality. - The impact of additional petroleum production on air quality stems principally from the emission of particulates into the atmosphere; however, some disturbance results from noise and vibrations.

Engine exhausts from vehicles and stationary engines result in emission of the products of combustion. The impact of such pollution dependent upon the size of the operation, climatic conditions, topography, and localized factors. Noise and vibrations from stationary engines used in drilling and production operations and transporting systems can disturb the natural environment. Air quality in immediate areas could undergo some temporary reduction because of removal of ground cover, dust from vehicle traffic, and from occasional equipment failure or blowouts.

Vapor venting from storage tanks and vessels, the burning of waste petroleum and chemical products, especially those containing sulfur compounds, could release hydrocarbons into the atmosphere, and objectionable odors.

It is highly unlikely that air quality reductions from operations associated with increased petroleum production would significantly alter biological conditions affecting the growth of flora. The feeding and nesting habits of birds and animals, wilderness qualities and hunting could be altered as a result of noise and vibrations associated with increased petroleum operations. After termination of operations a reversion back to original conditions would be expected.

(b) Water Quality. - The construction of roads for access into prospective petroleum producing areas could affect water quality where drainage patterns are disturbed or when erosion is possible. Canal dredging can avoid serious or permanent water quality impacts, but can result in temporarily increased turbidity and sediment suspension.

Entry of foreign substances such as oil, chemicals, brine, and waste materials into the water cycle can be a major environmental risk associated with petroleum production operations. Spills or leaks allowing such substances to enter the surface or ground water systems can result from human error and neglect; corrosion of pipelines and container vessels; pipeline breaks from vibrations, earthquakes, landslides, ruptures, or mechanical failures; burning pits and open ditches and

blowouts. During production, large amounts of salt water are usually produced as oil fields age. Such water can create disposal and pollution problems. A study by the Interstate Oil Compact Commission (IOCC) indicates that up to 25 million barrels of salt water are produced daily from the Nation's oil wells. Proper disposal of produced brines has been and continues to be of major concern to producing operators. Subsurface disposal is strictly regulated by state water resources agencies and disposal of salt water is not permitted in fresh-water streams (29, p. 147).

The principal causes of water pollution from barges transporting petroleum inland and on coastal waterways are loading and unloading operations; collisions; ship operations, such as bilge disposal; and human error. Data compiled from the Pollution Incident Reporting System (PIRS) of the U.S. Coast Guard show that there were 295 spills attributed to barges in 1970. Average size of the spills was estimated to average approximately 66 barrels per spill. Even though spill control methods are being improved, increased movement of petroleum has increased this pollution problem.

(c) Other Potential Impacts from Petroleum Production. - A potential source of land pollution is a blowout during drilling, but the frequency of blowouts is small. One hundred and six blowouts occurred in drilling 273,000 wells in 8 major oil-producing states

from 1960 through 1970. Most blowouts are from high pressure gas rather than oil. Other pollutants from blowouts are drilling mud and salt water (36).

The injury experience of the oil industry has been far less than that of mining. For example, injuries are about one-fourth of those attributed to coal mining. Moreover, historical injury rates of the oil industry are relatively constant, which indicates that increased production would not significantly increase the number of additional fatalities.

In exploring and pipelining, spills that occur normally would be small. Major spills could occur in drilling, production, and in transportation of petroleum liquids by marine transportation. The Environmental Protection Agency (EPA) estimated that 10,000 oil spills occur a year of which 2,500 are ground spills (29, p. 146). Most ground spills cause little ground drainage. According to the 1970 report of the Office of Pipeline Safety (Department of Transportation) on spills incidents, there were a total of 347 liquid pipeline accidents. Crude oil was being transported in 216 of the accidents. In those accidents, spills averaged approximately 1,780 barrels of crude oil. Principal cause of over 50 percent of the accidents was corrosion. Many pipelines are old, dating back to the 1920's before techniques for protection against corrosion became widely used. With the development and expanded use of cathodic protection of protection of pipelines, fewer accidents in new lines would be expected, but accidents from old lines will continue to be of concern.

2. Artic Oil and Gas

a. Arctic Oil Potential

The Prudhoe Bay field currently is estimated to contain 24 billion barrels of oil-in-place. At an estimated recovery rate of 40 percent, the current proved recoverable reserves of the field are 9.6 billion barrels of crude oil (37). These reserves alone make the Prudhoe Bay field the largest ever discovered on the North American continent (38). Nevertheless, the 9.6 billion barrel estimate may be a conservative indication of the crude oil potential of the field, the Arctic Slope province, and the adjacent regions of the Canadian Arctic.

Initial estimates of the reserves of newly discovered fields seldom indicate their full potential. As further drilling occurs, the proved area of pools is extended. Further developmental drilling and production provide additional information upon which more accurate estimates of reserves can be based. The application of secondary recovery techniques in the field also increases the amount of proved reserves (39).

The current reserve estimate for the Prudhoe Bay field is for unextended pools and assumes primary recovery only. Since the Prudhoe Bay discovery is quite recent and since relatively few wells were drilled at the time this estimate was made, it is highly probable that reserve estimates will increase as the field is developed. ARCO officials have recently indicated that they hope to recover ultimatey 65 percent to 70 percent of the oil-in-place (40). This increase in the recoverable percentage would increase present reserve estimates to 15.6 - 16.8 billion barrels of

recoverable reserves from present estimates of oil-in-place. With the addition of possible extensions, it is likely that at least 20 billion barrels of crude oil will eventually be recovered from the Prudhoe Bay field. This would make it the fifth largest oil field ever discovered (41).

The estimated reserves of the Prudhoe Bay field do not exhaust the petroleum potential of the Arctic Slope province in Alaska. The Prudhoe Bay field is located in the Colville Basin. Geologically, this basin is classified as an intermediate crustal type (i.e., its underlying crust is intermediate to that beneath continents and that beneath oceans), the basin itself being extracontinental (located on the margin of a continent) and sloping downward into a small ocean basin. Extracontinental, downward warping basins are among the richest sources of oil and gas in the world. Examples of such basins include the Arabian platform and Iranian basin (Persian Gulf), the East Texas basin, and the Tampico embayment (Mexico). Over half of the 119 known oil fields with at least one billion barrels of recoverable reserves are found in the 10 known basins of this type (42).

The ultimate potential on the onshore area in the Arctic Slope province (excluding the Arctic Wildlife Refuge but including Naval Petroleum Reserve Number 4) is uncertain. The platform along the Arctic coast gives considerable geologic indications of being very favorable for both oil and gas (43). Comparison with the history of similar basins indicates a high probability of further discoveries of varying size. One estimate made prior to the release of detailed information on the Prudhoe Bay field suggested an ultimate recovery of up to 30 billion barrels for the

province (including speculative reserves) (44). Other professional estimates made before and since that time (which incorporate higher recovery rates as well as greater optimism about additional discoveries) are somewhat higher, ranging up to 40 to 50 billion barrels (45). Considerably higher estimates than these have been made (46), but the geologic evidence for them is lacking.

The Beaufort basin east of the Richardson Mountains and encompassing the Mackenzie Delta also has considerable geologic potential for petroleum. Two discoveries of oil have been made already in this area by Imperial Oil, Ltd. They are considered to be significant, but official reserve estimates for them have not yet been published. Imperial has only indicated that it is optimistic about finding at least 2 billion barrels of recoverable crude on its Beaufort Basin leases (47).

The Chukchi and Beaufort Seas off the northern Alaskan and northern Canadian coasts are also believed to be potential oil and gas areas (48). These must be considered more speculative possibilities than the onshore areas. Imperial Oil, Ltd. currently plans to build artificial islands by dreding in shallow parts of the Beaufort Sea off the Mackenzie Delta later this year. Exploratory drilling will begin from these in late 1973 (49). Other shallow sections may be open to similar techniques. Drilling in deeper areas (50 feet or more) may however prove to be prohibitively expensive, even if geologic prospects are good. Hence, recoverable oil from deeper offshore areas may be limited.

B. Arctic Gas Potential

The Prudhoe Bay field has large reserves of natural gas dissolved in or associated with its crude oil reserves. Recoverable gas reserves in the field were estimated to be 26 trillion cubic feet as of the end of 1970 (50). An average of 750 cubic feet of dissolved gas per barrel (51) for the current oil reserves of 9.6 billion barrels would indicate reserves of approximately 7 trillion cubic feet of dissolved gas and 19 trillion cubic feet of associated gas. These reserves, which, like the crude oil reserves of the Prudehoe Bay field, are subject to extension and revision, constituted 8.9 percent of recoverable U.S. natural gas reserves at the end of 1970 (52). They also make the Prudhoe Bay field the 13th largest gas field ever discovered in the world (53).

The natural gas prospects of the North Slope are not limited to the Prudhoe Bay field. Several gas fields were discovered in the 1940's and 1950's on NPR-4, the largest of which was the Gubik field with 300 billion cubic feet of reserves. Geologic investigations of other parts of the North Slope have indicated a favorable potential for future gas discoveries within them as well (54).

Large reserves of natural gas in separate fields have recently been found in the Mackenzie Delta region. Imperial Oil has drilled two successful gas wells on Richards Island at the mouth of the Mackenzie River. Although no official reserve estimates have been

released for this new field, its reserves are believed to constitute a substantial proportion of the estimated 15 trillion cubic feet of gas reserves found in the Canadian Arctic so far (55). This would be a significant addition to current Canadian gas reserves (56) and would rank the Richards Island field among the 30 largest gas fields discovered in the world (57). The potential of this region is also believed to be much greater. Current exploration activity is very intense. One additional gas discovery was made in February 1972, 45 miles north of Inuvik and additional ones in the near future would not be surprising (58).

Given the large size of the Arctic gas reserves and the projected shortages in other sources of domestic supply, there is high probability that this gas will be developed and transported to U.S. and Canadian markets. Three different consortia have made proposals for gas pipelines down the Mackenzie Valley to these potential markets. However, many major uncertainties remain; for example, at this time industry experts differ in their opinions about how soon the gas caps in the Prudhoe Bay field can be tapped. Assuming 750 cubic feet of dissolved gas per barrel of oil produced, only 1.5 billion cubic feet per day of dissolved gas would be produced when oil production reaches a level of 2.0 million barrels per day. The additional gas required to meet the full planned pipeline capacity would have to come from the gas caps. The issue may not be fully resolved until

several years after oil production begins, at which time empirical data on the effects of production of associated gas on the production of oil will be available. It is likely that a gas pipeline to the Midwest and lower Canada would transport gas from both the North Slope and the Mackenzie Delta region.

c. Transportation

The proposed trans-Alaska pipeline is scheduled to have a capacity of 2 million barrels of oil per day for delivery to the West Coast. If built as planned, its full capacity will be required for meeting those needs. However, with the prospect of the increase in North Slope proved reserves through extensions and with further high potential of discovery of significant additional Arctic reserves, such additional reserves could be transported via a trans-Canada pipeline to the PAD II area (Chicago) for meeting growing Midwest needs. Such potential could be considered as a future alternative to shale oil production if and when the additional reserves materialize. However, even this significant potential could meet only a portion of growing U.S. oil and gas requirements.

Once construction of the trans-Alaska pipeline is underway, exploratory and developmental drilling should begin again with increased intensity. Several years following, enough should be known to provide better indications of total recoverable reserves,

particularly for the area between Naval Petroleum Reserve Number 4 (NPR-4) and the Arctic Wildlife Refuge. Knowledge of the full potential of other parts of the North Slope, such as NPR-4 and Canadian resources, is not likely to be obtained for several years after that. Leasing and drilling for NPR-4 would require new legislation permitting commercial development. Accordingly, it is not possible at this time to project the timing and magnitude of the development of those potentials.

d. Environmental Impacts

The potential environmental impacts associated with the development and transportation of Arctic oil and gas resources are set forth and evaluated in great detail in the Department of the Interior's Final Environmental Impact Statement--Proposed Trans-Alaska Pipeline, of March 1972 (15). In addition to the various environmental considerations associated with other onshore petroleum operations, environmental considerations are far more complex as a result of the severe climate and the fragile nature of the Arctic lands and surface resources. Detailed studies such as those made for the trans-Alaska pipeline would be required to assure that all design, engineering, development, construction, and operations were so conducted as to assure adequate protection of other land, resource, and environmental values. Examples of potential unique aspects include:

Projects Gasbuggy and Rulison are clearly demonstrating that the recovery of natural gas by nuclear explosion stimulation is technically feasible and holds economic promise. Both of these projects were essentially pilot experiments involving the detonation of a single nuclear explosive. The next development phase involves techniques for using multiple explosives in a single wellbore based on the fact that gas formations amenable to nuclear explosion stimulation are thicker than can be effectively and feasibly stimulated by a single explosion.

A recent report by the Atomic Energy Commission on the possible scope of nuclear stimulation, together with an economic assessment of the technical programs needed to achieve commercially viable application of nuclear stimulation of natural gas wells, indicates that, based on certain assumptions, over 10 percent of the Nation's current gas consumption could be met by gas from nuclear stimulation by a development rate of about 50 wells per year. Analysis of the data in the report indicates that it would take approximately 20 years before gas produced for stimulated reservoirs would be about equal to 10 percent of 1969 consumption. To accomplish this level of production, it would be necessary to explode 4,000 nuclear devices of 100 kilotons each in 1,000 wells over the 20 years.

Most natural gas resources amenable to nuclear stimulation are located in the Rocky Mountian region in fields estimated by the Bureau of Mines to have approximately 300 trillion cubic feet of gas potentially available by natural gas stimulation.

-- Thawing of permafrost from oil pipeline heat loss and from construction activities. The materials then could become unstable and flow or slide, especially on slopes.

-- Disruption of normal surface drainage and stream flows.

-- Surface or ground water contamination from construction, operations, and possible oil spills.

-- Destruction of fragile vegetation, particularly along pipeline right-of-way.

-- Fresh water fishery resources.

-- Wildlife resources in a wilderness type environment.

3. Nuclear Stimulation of Natural Gas Reservoirs

This alternative would require the utilization of nuclear explosions to increase natural gas production from known reservoirs. To the limited extent that natural gas supplies could displace crude oil markets, this might be considered as a partial alternative to oil supplies from oil shale. It is not now considered a viable alternative because commercial technology to permit safe use of nuclear explosions in fracturing of gas reservoirs has not been developed. The effectiveness of the alternative would be improved by increased Federal funding or other research incentives to accelerate development of technology. Assuming successful development of technology for commercial applications, the additonal natural gas supplies developed probably would be required to supplement conventional natural gas production to meet increasing domestic requirements.

Several years of development work need to be carried out before the nuclear stimulation technology will available for commercial applications. Assuming successful development of the technology, the AEC estimates that nuclear stimulation could add some 1 trillion or more cubic feet of natural gas to U.S. production per year beginning in the late 1970's This is equivalent to 2.7 trillion BTU's/day; a total of 6.0 trillion would be required to equal the energy potential derived from a million barrel per day rate of shale oil production.

Current emphasis in the U.S. Atomic Energy Commission's Plowshare program is to develop the technology for applying the effects nuclear explosions for the recovery and utilization of natural resources, primarily natural gas. The program plan is to continue the design and testing of a unique explosive, and to assess by field tests techniques for utilizing the effects of multiple nuclear explosives to recover natural gas locked in tight geological formations--gas which currently cannot otherwise be economically produced.

The current development program rate is not expected to provide for production quantities of natural gas that would be meaningful in comparison to the energy supply impact of the proposed oil-shale development to the year 1985. Accordingly, in the time frame of this report, nuclear stimulation of natural gas is not considered to be a viable alternative.

d. Potential Environmental Effects

In terms of environmental effects, field development using nuclear-explosive stimulation involves only two considerations which are not common to conventional field development. These considerations concern residual radioactivity in products and ground motion resulting from the nuclear explosion. Ground-motion effects can be managed by project design; that is, limiting the energy yield of the explosions at a given site to levels which will assure no structural damage to nearby man-made or natural structure. Some rockfalls and some minor architectural damage, such as plaster cracking, may occur. Owners of such damaged property would have to be reimbursed.

Most of the radioactivity produced by the explosions will remain underground trapped in the resolidified rock near the bottom of the chimney or attached to the rock surfaces in the chimney. Project design may pay particular attention to assure that the chimney remains isolated from mobile water. The formations of interest for nuclear-explosive stimulation lie generally at depths of 5-10,000 ft or deeper, are very impermeable, and would not be expected to contain mobile water. Therefore, this design consideration should not present a serious limitation on use of technology.

Water produced with the gas from nuclear-explosive stiumlated wells will contain tritium. Control methods to dispose of the tritiated water will have to be developed.

The question of small amounts of radioactivity in the gas itself is under careful study to evaluate the radiological implications. Any impact is expected to be very small.

More detailed discussions of environmental impacts applicable to the current nuclear stimulation program may be found in the Atomic Energy Commission's environmental statements concerning projects in Rio Blanco County, Colorado and Sublette County, Wyoming.

4. Increased LNG Imports

This alternative would require increased liquified natural gas (LNG) inputs to replace the energy expected to be available from 1 million barrels per day shale oil rate of production. Unlike oil, the importation of LNG, at present, is not subject to import quotas. The only legal constraint upon increasing importation is the necessity of obtaining FPC approval of any project. Before approving a project the FPC solicits the advice of the Departments of State and Defense.

Liquefied natural gas[1/] (LNG) has been in commercial use since 1940. Because of the more than 600: 1 volume reduction caused by the liquefaction process, large volumes of natural gas in a liquefied form are easy to transport and to store. Until recently LNG has been used by gas utility companies primarily for peak-shaving purposes and has been imported only in limited quantities. However, in March 1972 the FPC approved a 20 year project to import LNG from Algeria at the rate of 42 million cubic feet per day. Pending applications could increase LNG imports according to the schedule shown below :

LNG IMPORTS[2/]

Year	Quantity MMCF/Day
1975	800
1980	5,500
1985	8,200

If oil shale is not developed, and the expected production replaced by LNG, imports would have to increase in quantities approximating 6 billion cubic feet/day by 1985; an increase of about 70 percent over that shown above for 1985. An increase in imports of this amount would

1/ Natural gas becomes liquid at 258°F at atmospheric pressure.

2/ Federal Power Commission, National Gas Supply and Demand, 1971-1990, Staff Report No. 2, p.70

require between 2 to 4 additional LNG tanker shipments per day and an equivalent increase in the size or number of the highly specialized liquefaction and gasification plants now being proposed. While it may be physically possible to increase LNG imports by 70 percent over that projected, it is not known at this time if the economics of this alternative relative to other competing energy sources is attractive enough to stimulate the investments required to make LNGimports a viable alternative to oil shale development.

b. Environmental Impacts:

The alternative of increasing LNG imports could have an effect on the environment in several different ways. These potential impacts are analyzed below:

(1) Air Quality

The use of LNG imports as a substitute for the production expected from oil shale development through the replacement of liquid fuel products by natural gas. Natural gas is by far the least polluting of all fossil fuels. Its use could lead to a cleaner environment as discussed earlier in this volume.

(2) Construction and Operation of Regasification Plants

The construction of regasification plants will cause a disruption of the land and water resources resulting from the effects of additional dredging on the marine environment and from the preemption of coastal lands necessary to provide a site for the facilities. The extent and duration of this impact will depend on the size and location of the plants. For example, a plant now being proposed at Cove Point, Md., would regasify 650 million cubic feet per day and require a 1,022 acres of land. Another plant proposed at Savannah, Ga., would produce 335 million cubic feet per day and require 860 acres. LNG as an

alternative to shale oil could require the construction of at least six large plants with the consequent commitment of about 12,000 acres. During construction there will be some disruption of the land surrounding the plant. If proper techniques are used, this disruption, however, should be temporary.

A regasification plant also requires terminal facilities to permit the transfer of LNG from tankers to storage areas. In the Cover Point case, this could be accomplished by the construction of a mile-long pier into the Chesapeake Bay. The proposed Savannah River located would allow the tankers close to the plant. Both of these proposals would require dredging, causing increased turbidity of the water and disruption of bottom sediments. This disruption should also be temporary.

The construction of regasification plants would also have an impact on both land and marine animals. During the construction period there will be some damage to the natural habitat of the land animals. However, this damage will be permanent only in the area occupied by the plant. Any surrounding areas that are damaged should return to a near-normal condition after construction is completed. The dredging operation could also disrupt the marine habitat, especially in the case of bottom-dwelling organisms. In most cases, this disruption would be temporary.

The choice of the plant site is an important factor in minimizing the impact of scenic qualities and recreational activities. An esthetically pleasing plant would reduce the disruption of scenic views. The increase in ship traffic will inevitably have an effect on water-oriented recreational activities, depending on its location.

The actual regasification process involves little environmental risk. The Cove Point plant plans to use natural gas in the regasifica-

tion process and will avoid potential water and air pollutants. The Savannah plant plans to use water drawn from the river to regasify the LNG. After going through the vaporizers, the temperature of the water will be lowered about 5°F and then be returned to the river. Lower water temperature could actually be beneficial by allowing the water to hold more oxygen, which might counteract some upstream-caused pollution.

(3) Transportation

After the LNG has been regasified it can be transported through any existing gas pipeline. Thus, existing pipelines will be used if they are available. New pipelines, however, will be required in some areas. The potential enviromental impact of the new lines has been examined in the previous section of this volume.

The chance of a major spill is a potential hazard associated with increased LNG imports. A study conducted by the Bureau of Mines has indicated that under certain conditions there exists the possibility of small-scale explosion resulting from a LNG spill (1). They were not able, however, to predict the result of a large-scale spill on open-water. Another study by Shell Pipeline Corporation (2) concluded that there was no danger of normal LNG exploding when spilled on water since an explosion would result only after the methane content of the LNG has reached 40 percent. Normal methane content is 80-90 percent and the boiling rate is 0.2 percent-0.3 percent per day. With present day shipping practices, a reduction to 40 percent would not be possible. Further discussions with the Bureau of Mines researchers indicated that an explosion resulting from a LNG spill in open water is unlikely. The chief hazard from a spill would be fire.

1/ Bureau of Mines, USDI, "Hazard Associated with the Pillage of Liquefied Natural Gas on Water" pg. 23.

2/ Shell Oil Company News Release, February 21, 1972.

5. Coal

The premise of this report which discusses the alternatives to shale-oil production is that energy source materials would primarily substitute or supplement for one another on the basis of their physical state, liquid, solid, or gas. Secondly, the rate of the alternative as supplementary energy source material is considered in relation to the total energy picture.

Solid coal is not an alternative to liquid shale oil in a direct way; however, full consideration must be given to the use of coal since it is the most abundant fossil fuel in the nation and may be converted to clean liquid and gaseous fuels.

Coal underlies 458,600 square miles in 37 states. The remaining coal resources were estimated, as of January 1, 1967, to total 3,210 billion short tons (59). The Department of the Interior (60),p. 29) slightly revised that estimate to 3,200 billion short tons in January 1972 and further estimated that 2,800 billion short tons are at depths less than 3,000 feet, and 1,600 billion short tons are less than 1,000 feet below the surface. About 390 billion short tons are commercially recoverable under present economic conditions and mining technology (61).

The quality of coal has become increasingly important as restrictions are updated, and new regulations are imposed by local, State, and Federal governments on the utilization of fuel containing excessive quantities of sulfur, nitrogen, and particulate matter. As a result of these restrictions, low-sulfur coal, or coal containing less than

one percent sulfur, is in great demand for power generation, steel, and manufacturing. Throughout the United States, utility companies in particular and other fossil fuel consumers are being forced by public demand and law to use low-sulfur coal.

At present, the greatest need is for low-sulfur bituminous coal with a low ash fusion temperature for use in the power plants of the eastern United States. There is an acute shortage of this type of coal east of the Mississippi River. However, there is an abundant supply of low-sulfur bituminous and sub-bituminous coal and lignite in the Rocky Mountain States that could be used in power generation, coal gasification, and coal liquefaction plants.

The remaining resources of low-sulfur bituminous and sub-bituminous coal and lignite in the Rocky Mountain States were estimated to be 874 billion short tons as of January 1, 1967 (59),p. 33); 188 billion short tons of the remaining resources are in beds, usually 10 feet or more thick, and less than 1,000 feet below the surface. The recoverable resources are about 440 billion short tons to a depth of 3,000 feet and 94 billion short tons to a depth of 1,000 feet.

Since 1967, coal production in the Rocky Mountain States has been about 100 million short tons. Therefore, it is assumed that 94 billion short tons still are available as of January 1972 (Averitt, Paul, 1972, oral communication). Approximately 45 billion short tons of the recoverable resources could be extracted by open pit mining (59), and 25 billion short tons are so well known as to character, thickness, and tonnage that they are considered as reserves (62).

By 1985, the energy supplied by 1 million BPD of shale oil would be, on an annual basis, equivalent to 95 million short tons of 11,000 Btu coal. If the oil-shale leasing program was not initiated, the energy supplied by the projected oil shale that would have been produced in the period from 1974-1985 would be equivalent to 482 million short tons of 11,000 Btu/lb coal. However, coal production could be increased on a graduated scale. In 1974, approximately 1 million short tons of coal would be required to provide the energy projected to be obtained from oil shale. In 1985, 95 million short tons of coal would be required.

The large coal resources of the Rockv Mountain States, if interchangeable for other energy source forms, are adequate to provide the energy needed if the oil-shale lease program is not developed. The degree of its substitutability in solid or synthetic product form could be a controlling factor. The impact of developing a coal industry capable of producing approximately 1/2 billion short tons of coal during the period from 1974-1985 would have environmental and socio-economic effects approximately equal to the proposed program.

At present, large open pit coal mines may produce 5 million short tons of coal per year; large underground mines may produce 2 million short tons per year. In order for the Rocky Mountain coal industry to produce the 95 million short tons of coal needed by 1985 (the equivalent of the energy supplied by 1 million BPD of shale oil) approximately 50 large underground mines or 20 large open pit mines, or many smaller

mines, or some combination thereof, would be necessary. Such mines could only become operational after considerable planning including environmental considerations based on determining the adequacy of large reserves, adequacy of water supplies, construction of utility and transportation facilities, and determination of market requirements. Local, State, and Federal Government regulations regarding air, water, and noise pollution also would have to be met.

Many very thick and closely spaced beds of lignite and subbituminous coal, containing about one-half of the remaining coal resources in the Rocky Mountain States, underlie the northern part of the Great Plains. The coal generally has a low ash fusion temperature, a low sulfur content, a substantially reduced heating value, and high volatile matter content. These characteristics suggest that this coal would be preferred for power generation, gasification, and liquefaction.

The total remaining coal resources in the basins of the Rocky Mountains are very large, nearly as great as those in the Northern Great Plains, but extremely thick beds are a rarity rather than a common occurrence.

At a few localities within the Rocky Mountain States, deposits of metallurgical grade bituminous coal and anthracite are known; some of these deposits are actively mined. Generally, the coal from these deposits is not suited for power generation, gasification, and liquefaction.

The coal resources of the Rocky Mountain basins are so large that the locations of open pit and underground mines would likely be determined by nearness to adequate water supplies, transportation facilities, and the plans for mine-mouth power, gasification, and liquefaction plants. About 45 percent of the coal resources of the basins is owned by the Federal Government, 13 percent by Indian tribes, 13 percent by State governments, and 12 percent by railroads. The large amount of governmental ownership of the resources indicates that mining, rehabilitation, and environmental controls and procedures imposed on mining operations could be fully effective, since they would be administered in large part by the Department of the Interior and cooperating State governments.

a. Environmental Impacts of Coal Utilization

The expanded use of coal power generation could be a viable alternative to the use of less abundant fossil fuels (oil and gas). Major limiting considerations are those associated with the extent to which it can substitute for the form of energy source to be displaced and the solving of problems associated with the meeting of air quality standards.

The sulfur content of U. S. coals ranges from 0.5 to over 7 percent. About 65 percent contain 1.0 percent or less, and most of such coals are found in the western states, far removed from the area of the current major demand and use.

Most current production comes from states east of the Mississippi from which only 20 percent of the reserves contain 1.0 percent or less sulfur, while 43 percent contain more than 3.0 percent sulfur. Unless control measures are available and employed during combustion, sulfur oxides are emitted to the atmosphere causing undesirable air pollution environmental impacts in direct proportion to the sulfur content of the coal feedstock.

Recent environmental regulations applicable to new electric generating facilities restrict the emission of sulfur dioxide to 1.2 pounds per million Btu of fuel as fired; for bituminous coal, this is equivalent to about 0.7 percent sulfur. It is necessary, therefore, to reduce the sulfur content of the coal prior to burning or to remove sulfur oxides from stack gases following combustion in order that coal may continue to be used for power generation.

Mechanical cleaning of raw coal is only a partial solution to the problem, since only a small fraction of American coals can be cleaned sufficiently to meet sulfur emission controls and standards. Mechanical cleaning affects only pyritic sulfur and leaves untouched the 40 to 60 percent of the sulfur that is bound in the organic structure of the coal. In addition, freeing the small particles in which pyrites occur requires fine grinding prior to cleaning, which in turn adversely affects the cleaning efficiency and restricts the methods of cleaning that can be applied. Tests of some 322 coals representing most of the steam coals produced in eastern United States showed that, under optimum conditions

and present technology, less than 20 percent of these coals could be cleaned to 0.7 percent sulfur (Bureau of Mines).

The status of technology for abatement and control of sulfur oxides in combustion gas was recently reviewed by the National Academy of Engineers, National Research Council, whose report (63) concluded that ". . . commercially proven technology for control of sulfur oxides from combustion processes does not exist." The conclusion remains valid, although a number of systems are either being installed or operated at the present time on commercial plants to determine the operational and economic feasibilities of the processes (63).

President Nixon in his June 4, 1971, message to the Congress on Clean Energy emphasized the need for a greatly expanded effort on sulfur oxide control technology. Federal funding is being directed to demonstrate six different techniques during the next three or four years.

Coal, especially high-sulfur coal, is available in large quantities in close proximity to consuming markets, and many existing power plants can burn only coal. New coal burning plants could be built if air quality standards can be met. Process economics for coal desulfurization are marginal, and optimistic assessments of economics are generally based on a substantial credit for sale of byproduct sulfur, but the supply of sulfur has exceeded demand recently, and substantial additional production of elemental sulfur could cause further disruption of the domestic sulfur industry.

b. Environmental Impacts of Underground Mining

The coal in the Rocky Mountain States that is too deeply buried to be extracted by surface mining would be recovered by underground mining. The selection of underground mining techniques would depend upon local geologic phenomena that might influence mining conditions. The type and extend of such phenomena would affect not only the economics of mining but would also affect severity of surface and subsurface environmental impacts. Because most of the coal resources in the Rocky Mountain States are on public, Indian, or State lands, environmental impacts can be minimized by effective enforcement of Federal and State operating regulations.

If the oil-shale leasing program is not initiated and if the Rocky Mountain States should have to produce an equivalent amount of energy from coal (490,000,000 short tons for the period 1974-1985), the severe short-term environmental impacts of surface mining could be minimized by underground mining. The manpower requirements and capital expenditures, however, would be large. On the basis of an annual production rate of about 2 million short tons per underground mine, nearly 50 underground mines would be needed, imposing still a considerable environmental impact. Manpower for these operations would total about 25,000 employees and capital expenditures would approximate $1.2 billion (34). However, these requirements could be spread over the 1974-1985 period, which tend to lessen the impact.

Social costs in terms of health and safety of mine employees must be considered along with the capital expenditures and the environmental

costs of underground coal mining. A total of 220 men were killed in 1970 in underground coal mining operations---fatal injury frequency rate of 1.00 per million manhours or 0.32 per million tons of production. Enforcement of existing mine safety laws and the introduction of new technology should reduce the fatality rate in the future; no more than about 150 additional fatalities could be expected during the 12-year period from 1974-1985 at the underground mines developed to supply the same amount of energy as expected from shale oil.

Subsidence of the ground surface is common above many abandoned and some active coal mines. The amount of subsidence relates to the mining method employed, the amount of coal removed, the thickness of the coal bed, and the composition and strength of rocks overlying the coal. Subsidence of large areas commonly destroys man-made structures. It also disrupts the ground-water hydrology, and surface and sub-surface water recharge. It may intercept or short-circuit both surface and subsurface water moving across or through the area that has subsided. Subsidence may increase vertical permeability so that recharge from the surface is increased. Subsidence also may provide increased communication between aquifers. It also, in some localities, causes land slides and minor earthquakes.

The most successful method of preventing or alleviating surface subsidence problems is to plan mining so that more pillars are left untouched. Unfortunately, this procedure results in less coal recovery. Much additional research is needed to develop methods of underground mining which will minimize subsidence of the surface. If such methods

cannot be implemented, the best solution may be to achieve as complete recovery of coal as possible during mining, than allow controlled subsidence to the point of natural stablization which will permit use of land surface.

Ground and surface waters entering active underground mine workings are normally pumped to the surface for disposal. Because of the low-sulfur content of most Rocky Mountain coals, it is uncertain whether acid-mine water would be a problem in areas of large-scale mining and above average precipitation. The large volumes of sludge resulting from such treatment could be emplaced either in abandoned mine workings or in protected surface mine waste disposal areas. Acid-mine water may drain from abandoned mines and workings for long periods giving a significant cumulative effective. It may be prevented by locating mine entries at elevations above the prevailing drainage level, by sealing abandoned mine entries, and by emplacing dams at critical points in abandoned underground entries and haulageways.

In most coal producing areas, mining and processing wastes contribute large volumes of sediment to nearby streams, are sources of air pollution. However, this is an area in which satisfactory handling procedures can be implemented to avoid this contamination.

The most commonly used technique of preventing widespread scattering of mining and processing wastes is to compact the waste in layers, followed by sealing with incombustible soil, after which vegetation is established to help prevent infiltration of surface and to minimize erosion (64).

An alternative to surface disposal of mine and coal processing waste is to return it to abandoned underground mine workings. This is currently being done to control surface subsidence in mined areas in compliance with restoration provisions of the Appalachian Regional Development Act of 1965, as amended (65, p. 24). Methods of returning the waste to mined-out areas concurrent with active mining would appear to warrant attention of mining-method researchers.

Dust from mine-access roads, coal handling, and processing can be alleviated. Road dust can be minimized by hard surfacing, or through abatement techniques, such as oiling or chemical treatment of the road surface. Dust from coal handling and processing can be abated by spray treatment at transfer points and by enclosing coal-handling and processing structures. Dusting problems in live coal-storage piles can be reduced by water sprays or oiling; dead storage piles can be sealed with asphaltic or chemical materials.

The potential for long-term environmental impacts from an underground mine can be diminished by identifying and eliminating pollution sources prior to closure of the mine. Most pollution sources can be

eliminated by sealing and revegetating waste disposal areas; sealing abandoned mine openings; dismatling and removing abandoned mine buildings and structures; and scoring, fertilizing, and revegetating areas formerly occupied by buildings and structures, mine roads, and supply storage areas.

Underground mining is less subject to noises and vibrations than surface mining, and the surface environmental effects from drilling, blasting, and spills and leaks are minimal. Modifications of the habitat, alteration of ground cover, alteration of surface drainage systems and the necessity of fertilization application are also less severe.

The following environmental effects underground mining are generally more severe than those associated with surface mining because the underground mines are generally deeper: Extensive and severe alteration of ground-water hydrology, the necessity of well drilling and fluid removal, the techniques of product processing and resultant waste, liquid effluent discharges and most accidents.

c. <u>Environmental Impacts of Surface Mining</u>

Near surface coal (0 to 200 feet) generally can be extracted by open pit or surface mining. This method involves the removal of the top soil and rock (overburden) to expose the coal bed, removal of the coal, and replacement of the spoil material and, in some instances, replacement of the top soil. Usually this is accomplished by working in large parallel trenches using the overburden of the second trench, or cut, to fill the first trench.

In 1929, open pit coal production amounted to 3 percent of the total United States production (<u>66</u>, p. 9). In 1969, however, open pit mining accounted for approximately 200 million short tons or 35.2 percent of the 560 million short tons total United States production (<u>67</u>, p. 309). The amount of surface-mined coal for the year 1971 will have increased to about 47 percent of total U.S. production according to recent estimates. The preceding illustrates the slow growth of open pit mining from 1929 to 1969 and a spurt in production from 1969 to 1971. The principal reasons for this growth are (i) full production can be reached quickly, (ii) the coal can be mined more cheaply, and (iii) open pit mining is much safer than underground mining.

Social costs in the terms of health and safety of mine employees must also be considered. A total of 31 men were killed in 1970 in open pit coal mining operations. On the basis of the 1969 fatal injury frequency rate of 0.14 million short tons of production continuing until 1985, approximately 70 additional fatalities could be expected during

the period from 1974-1985 at the open pit mines developed to supply the same amount of energy as expected from shale oil.

The use of coal as an alternative energy source, if the oil-shale leasing program is not initiated, would result in the need for additional mining of nearly 490,000,000 short tons of coal over the period from 1974-1985. If the required 490 million short tons of coal production, over a 12-year period, should be furnished totally by surface mines, 20 mines of 5 million short tons annual capacity each would be the minimum number of operations needed. Currently, a mine of this magnitude employes 610 personnel with a capital expenditure of about $40,000,000. Therefore, for surface mines to supply the 96 million tons of coal needed annually, 12,200 employees would be needed with a total capital expenditure of nearly $0.8 billion or between $6 and $9 per ton of annual production (34, p. 41). This capital expenditure does not include the necessary financing for coal cleaning facilities.

Open pit mining disturbs considerably more surface acreage than underground mining. Underground mining operations, however, because of lower recovery per unit of area, actually disturb more acreage in three dimensions than an open pit mine producing a similar tonnage. As of 1967, it is reported that open pit coal mines were responsible for 41 percent of the land disturbed by surface mining in the United States (68, pp. 53-54).

Predictions regarding the total size of the areas which would be disturbed by the surface mining of 96 million short tons of coal are shown in the following table:

Production by surface mining methods

(Based on 1,800 tons per acre foot)

(Figures based on 96,000,000 tons production for the year 1985)

Coal bed thickness, ft	Recovery factor, pct	Coal available per sq mile at 80 pct recovery, tons	Area disturbed in 1985, sq miles
10	80	9,216,000	10.9
15	80	13,824,000	7.3
20	80	18,432,000	5.5
25	80	23,040,000	4.2
30	80	27,648,000	3.6
35	80	32,256,000	3.1
40	80	36,064,000	2.8
45	80	41,472,000	2.5
50	80	46,080,000	2.2

Open pit mining of a 10-foot bed of coal, sufficient to satisfy the cumulative 1/2 billion total short ton energy requirement between 1974 and 1985 would necessitate the disturbance of 34,050 acres of land. Surface production from a 50-foot bed would disturb 6,800 acres. Regardless of whether the coal is produced from a 10-foot bed or beds up to 50 feet or more in thickness, rehabilitation of disturbed lands would be required, and speed in reclaiming and revegetating mined lands would be important in order to minimize environmental degradation.

The following table shows the rehabilitation cost on a per ton basis to estimate the cost of the restoration required:

Estimated costs in cents per ton of coal for regrading, reseeding, and revegetating strip-mined lands to a pleasing, natural contour

Assumed tonnage of coal recovered per acre	Estimated costs of reclamation per acre (dollars)				
	$1,000	$2,000	$3,000	$4,000	$5,000
10,000	0.10	0.20	0.30	0.40	0.50
20,000	.05	.10	.15	.20	.25
30,000	.033	.066	.10	.13	.17
40,000	.025	.05	.075	.10	.13
50,000	.02	.04	.06	.08	.10
100,000	.01	.02	.03	.04	.05

Climatic conditions are extremely important in considering the rehabilitation, reseeding, and revegetation of mined lands in the Rocky Mountain States. Obviously, without proper moisture, the reseeding of reclaimed lands would serve little purpose and erosion processes would soon destroy the contour of the rehabilitated lands.

Disruption of the land surface by open pit mining would, temporarily have adverse impacts on all vegetation, forestry, grazing, crops, birds, land animals, endangered species, habitat, water supplies, and water quality, all of which would limit the enjoyment of hunting, fishing, and allied leisure time activities in addition to affecting scenic vistas and open spaces. Furthermore, nearby agricultural, residential, commercial and industrial activities could be curtailed or endangered by environmental effects that were propagated beyond the area of mining. Reclamation of the area would restore it's long-run productivity.

Few coal deposits are free of contaminants; therefore, it can be assumed that under ideal conditions, a 5-percent washer loss would occur. The handling and placement of 25 million short tons of waste material (over 12 years) must be considered. The problem would not be major for surface mines in that the pits from which the coal would be extracted could receive this material. Ultimately, the mine pits would be backfilled, the spoil banks topped off or leveled, the high-walls backsloped, the top soil replaced, and the area reseeded.

Other short-term problems related to surface coal mining are acid mine water developing in the open pits, in spoil piles, and in mine processing waste; silt eroding from the pits, processing waste and spoil piles; and dust blowing from the pits, spoil piles, truck haulage roads, railroad cars, mine processing plant, and processing waste piles.

In comparison with underground mining, surface mining is the source of greater volumes of noise and vibrations from blasting, drilling, heavy mining equipment, trucks, and landslides. Modifications of the habitat, alteration of ground cover, alteration of drainage systems, destruction of land forms, and siltation of nearby streams are also more pronounced in surface mining. Landslides are more common, and subsidence does not occur unless the area has been underground mined. Also, there is a major conflict with timber, grazing, wildlife, and other resource use.

The end use to which surface-mined lands can be reclaimed concurrent with mining is limited only by the capacities of men operating

within prevailing geologic, technologic, and economic restraints. In effect, the short-term economic and energy profits derived from surface mining should be compared with a possible long-term degradation of the environment.

d. Waste Disposal

Large volumes of waste are generated during coal mining and processing. The volume of mine waste depends on the type and characteristics of top and bottom strata, the continuity of a coal bed, the existence of fault zones, and the tonnage of county rock that must be mined. The type and volume of waste discarded during coal processing depends upon the specifications for which the coal is being prepared, characteristics and amounts of impurities in the coal bed being mined, and the efficiency and type of coal processing equipment.

Uncontrolled disposal of coal mining and processing wastes, especially those containing carbon and trace amounts of sulfur, constitute a source of land, water, and air pollutants.

Water flowing over waste disposal areas commonly transports silt and leached minerals to adjacent land and surface water drainage areas. The cummulative effect of this leaching can be severe.

In addition, dust-size particles commonly are transported by winds to contaminate adjacent land and water resources. Both the leaching and dust problems give long-term undersirable effects. If a waste pile containing large amounts of carbon ignities, noxious gases enter the atmosphere where they are hazardous to plants, animals, and humans (69).

Waste disposal areas require a commitment of land resources. Furthermore, if poorly constructed and uncontrolled, these waste areas present an unattractive appearnce to viewers.

Slides and slump failures commonly occur where waste is deposited on slopes and where an improper combination of moisture and clay minerals in the topsoil or in the waste act as lubricants. In such unstable conditions, large quantities of waste can move downslope and deposit on land and into water resources. Slides also are safety hazards to people and animals.

Should fine coal cleaning be included in the preparation processes for Rocky Mountain coals, the discarded fine waste would probably be deposited in slurry impoundments where the water would either be decanted for recycling to the preparation plant or allowed to evaporate. Poorly designed impoundment dikes in the past have permitted percolating leachate water to enter downslope surface water drainage areas and degrade their water quality. Also, such impoundments are subject to rupture which could lead to floods and/or landslides.

In addition, construction of impoundments on underlying pervious bedrock commonly results in infiltration of the ground water table by mineralized water or in percolation of such water through the base of dikes to enter downstream surface water drainage systems where these types of leakage commonly affect aquatic plant and animal life. Unless measures are taken to seal and revegetate both coarse and fine waste upon abandonment of waste disposal areas, many unfavorable impacts can continue for decades.

e. Coal Transportation

It is assumed that the total quantity of mined coal supplied over the period 1974-1985 could not be adequately handled by today's transportation network at a reasonable cost; therefore, all new power, gasification, and liquefaction plants would be situated at, or near, the actual mine locations, thereby having nominal effect upon existing transportation systems. The end product of the above plants (electricity, synthetic gas, and synthetic oil) could be more readily transported to the market areas by transmission lines and existing, or new, underground pipelines. Surface or underground transmission lines and pipelines should cause fewer environmental impacts than increasing the mileage of highways or rail routes and building the vast number of highway trucks and hopper cars necessary to move this vast quantity of low sulfur fuel.

Four systems of transporting coal would be available in the Rocky Mountain States for moving coal from a mine to a point of utilization. These systems would be: trucks, railroads, conveyors, and coal slurry pipelines. A fifth system, water transportation, may be discounted because of the lack of navigable waterways. Each system has advantages that would make it economically attractive for transporting coal to a point of utilization. Selection of a system would be strongly influenced by the distance to a utilization plant.

The major adverse environmental impacts of alternative transportation systems are air and noise pollution, safety, the amount of land required for rights-of-way, trash disposal, and aesthetics.

Air pollution sources are exhaust emissions, road dust, and coal dust. The level of adverse exhaust emissions can be reduced through efficient engine maintenance; road dust can be reduced by haul-road surface treatment such as hard surfacing, oiling, or applying water-chemical solutions; and coal dust can be reduced by truck covers and spraying. Although mufflers can reduce the level of noise pollution, truck haulage, because of the large number of noise sources and frequent trips, is commonly recognized as the noisiest system of transportation.

Collisions between trucks, other vehicles, and animals can occur but do not normally constitute a serious public hazard because haulage roads generally are confined to mine property.

Secondary environmental impacts from truck transportation arise from improper disposal of tires, expended oil, and used parts. These items can be disposed of in open cuts of surface mines and then buried with reclaimed spoil and revegetated. In addition, special disposal pits can be excavated at underground mining operations where these items can be buried and the area revegetated. Depending on economics of the particular mining operation, a reasonable alternative would be to recycle these items.

Rail transportation systems using diesel locomotives are sources of air and noise pollutants from engine exhaust systems. Effective maintenance of engine combustion systems and efficient mufflers can reduce the air and noise pollution levels from these systems. Coal

dust lost in transit can be reduced by using partially covered hoppers or by drilling the coal during loading. Dusting during loading and unloading can be reduced with a combination of dust suppression sprays and enclosed chutes or bins.

The right-of-way for a railroad constitutes a permanent commitment of the land surface to this use making it unavailable for other uses. Free travel of vehicles, people, and animals across the committed area is restricted; however, the potential for collisions with trains exists.

In the open or scenic areas of the Rocky Mountain States, railroad rights-of-way may be considered as aesthetic intrusions, especially if large trestles, overpasses, or cut and fill areas are required. Cut and fill areas can be constructed with gentle slopes and revegetated, and borrow areas can be reclaimed as mentioned in conjunction with truck transportation systems. The visual impact of trestles, overpasses, and other appurtenant structures can be minimized with effective combinations of eye-pleasing designs and unobtrusive colors.

Conveyor system installations likewise constitute a permanent commitment of the land surface and restrict free movement of vehicles, people, and animals. The right-of-way width is less than that required for truck or railroad transportation systems. Uncovered or partly covered conveyors allow loss of dust in transit because of exposure to winds. Uncovered transfer points also are a potential source of dust when suppression devices are not provided. Open, or partly covered conveyors, constitute a safety hazard to persons or animals when a

support structure is installed close to the ground. Conveyor systems can be fenced or completely enclosed to eliminate dusting and safety hazards to humans and animals.

Conveyor support structures, either frame or suspension type, as well as the conveyors, are obvious visual intrusions, especially at points where the conveyor crosses deep drainage systems. Color treatment of support structures, enclosures, and transfer structures would lessen but not eliminate this impact.

The principal impacts of coal slurry pipeline systems are: the permanent commitment of land, providing an adequate water supply, and water disposal. Large quantities of water, at the rate of one ton of water per ton of coal, are required to transport coal in the Black Mesa, Arizona, Pipeline (70). In water deficient areas this method may not be an efficient transportation alternative, particularly where the water must be supplied by deep wells which, when pumped, could have a draw-down effect on shallower wells that supply people or livestock. Additionally, water disposal problems at the terminus of a pipeline could have severe impact on water quality if not properly contained or when not economically feasible to recycle the water for transportation purposes. Coal slurry destined for power, gasification, or liquefaction plants could be dewatered, the "spent" water used for cooling tower makeup, ash handling, and/or evaporated in disposal ponds. The Mohave generating station in Nevada is utilizing water from the Black Mesa Pipeline in this manner.

The disposal of solids and water removed from sections of a plugged pipeline could cause environmental impacts. Holding ponds, equal in capacity to the upstream pipeline, could be provided at pumping stations and at the coal slurry preparation plant for disposal of removed plugs. The water could be evaporated and the coal could be left in the impoundment unless provisions are made for recovery. Compaction and sealing would prevent spontaneous ignition, erosion, and accompanying siltation of the coal left in impoundments. The surface of the impoundment can then be revegetated with indigenous plants to inhibit erosion.

f. Coal Gasification

Through hydrogenation processes, it is possible to convert coal to various forms of liquids and gaseous forms as a substitute for natural oil and gas. One form may be as a low Btu gas suitable for power boiler utilization for production of electrical energy. Another more sophisticated gasification process could produce a high Btu gas suitable for direct distribution and use through existing pipelines (71, 72).

While no coal to pipeline gas process has yet reached the commercial stage in the United States, several companies are studying commercial application of a variety of gasification processes, some of which have been known for several years. For example, the Lurgi fixed bed process has found commercial use in India, Australia, Germany, South Africa, Russia, and Great Britain for many years.

The feasibility of using such processes as an alternative to shale oil depends upon the rate at which technological systems are developed, tested, and proven to be economically viable and commercial scale plants could be built. Any commercial gasification plant system would have to produce about 6 billion ft^3/day of 1,000 Btu/ft^3 gas to be equivalent in energy potential to 1 million barrels/day of shale oil. Many of the individual units for a commercial gasification process have been tested; howver, synthetic gas has not yet been economically proved. Under current donditions, the National Petroleum Council (NPC) has estimated that approximately 1 trillion ft^3 per year of gas from coal will be available by 1985 (81, Vol. I, p.9 13). Under accelerated conditions, the NPC estimates that this could be increased to a maximum of 3 trillion ft^3 per year (81, Vol. I, p.9 54). The difference, 2 trillion ft^3 per year, represents about 5.5 trillion BTU's per day. Since the energy available from 1 million barrels per day at shale oil production is 5.8 trillion BTU's per day, acceleration of coal gasification can be considered an alternative to oil shale development.

The production of 2 trillion ft^3 of synthetic gas per year would require approximately 22 plants that each produce 250 million ft^3 per day. The coal mining capacity (strip) that would need to be developed to support this output would approximate 150 million tons per year. The environmental impacts of coal mining have been described in the previous chapter; the potential impact from the plants themselves are considered separately below.

Experiments in the underground gasification of coal date back to the 1890's. The most recent work in this country was undertaken by the Bureau of Mines from 1946 through 1956. The object of this work was to determine

the feasibility of bringing the chemical constituents or the energy of coal to the surface in a gaseous form, usable in the synthesis of liquid or gaseous fuels, organic chemicals, or the production of electric power. Other objectives were to materially reduce or eliminate underground mining operations, to obtain useful products from coal or other carbonaceous materials that lie in beds that are not profitable to mine, and to recover the chemcial constituents or the energy of coal remaining in areas when mining operations have been completed. From an economic standpoint, the cost of production of synthetic liquids and gases through in situ processes suitable to meet current energy requirements was found to be excessive and, therefore, was discounted. A recent review (73) suggests that due to advances in related petroleum technology, underground gasification of coal should be reexamined. However, this renewed interest holds little promise for significant increases to the Nation's supply of clean energy until, possibly, after 1985.

g. Coal Liquefaction

Like a synthetic gas, a synthetic oil can be made from coal. There are presently no coal-to-liquid conversion plants in the United States; however, a few prototype commercial plants may be in operation by 1985. Some recent research in this area is covered in references 48 through 77.

A commercial plant would have to produce approximately 1.24 million barrels of synthetic crude oil through some liquefaction process to be equivalent to 1 million barrels of shale oil.

h. Potential Environmental Impact of Coal Conversion Processes

Like natural gas, synthetic natural gas, and oil from coal are

clean-burning fuels because the sulfur has been reduced to very low values, and no particulate matter is emitted at the point of combustion.

Since there are ample reserves of coal in this country, conversion plants would afford a reliable supply of synthtic fuels for many years, thereby reducing dependence on imported oil and LNG, and concomitantly lessening the potential adverse environmental effect associated with shipping these fuels and delivering them in ports.

Site preparation and plant erection will have environmental effects; the kind, importance, and magnitude of which will depend on the site that is selected. Consideration would be given to the effect on factors such as earth, water, flora, fauna, land use, recreation, and aesthetics.

Plant operation, consisting of handling and transporting the coal to the process, and converting the coal to gas and/or oil will involve very large quantities of water for cooling and scrubbing gases, and very large quantities of devolatized coal, called char, which will be burned in boilers to generate process steam and power, or gasified to make process hydrogen. Major emissions that must be controlled are:

a. Sulfur and nitrogen oxides, bottom ash and fly-ash from the plants generating process steam and power. Fly-ash emission from boiler stacks can be controlled, and furnace-bottom ash and slag are handled routinely in the generation of power using coal. However, it may become desirable to locate large coal-conversion plants near large strip mine, where ash and slag from the process would be returned to the open cuts, and the ground restored in accordance with environmental considerations. The technology for controlling

sulfur and nitrogen oxides, however, is not yet available commercially.

b. Contaminated water discharges containing phenols, cresols, benzene, oils, tars, and ammonia; gaseous discharges from the Claus tail gas containing some hydrogen sulfide and sulfur dioxide; and solid discharges such as char and ash; and possibly solids from gas-scrubbing systems using solid sorbents such as dolomite. Process waste waters can be partly controlled by treatment and reuse. Claus tail gas can be scrubbed free of sulfur compounds. Waste solids such as spent dolomite may present disposal problems in terms of available space and/or surface water contamination, but these are not insurmontable problems.

c. Noise will occur from mechanical equipment, injectors, and pressure-reduction devices, but is unlikely that it would be a problem beyond the plant property lines.

To illustrate the order of magnitude of the major emissions that would have to be handled from a commercial coal-to-pipeline gas plant, the Federal Power Commission gave the following estimates, based on a plant producing 250 million standard cubic feet per day of pipeline gas, from coal with 3.7 percent sulfur:

	Tons per day
Sulfur (mainly as hydrogen sulfide)	300-400
Ammonia	100-150
Phenols	10-70
Benzene	50-30
Oils and tars	trace to 400
Ash (based on coal with 10 percent ash)	1500

The Federal Power Commission report describes in detail the general means for controlling contaminants in the process waste waters, and the various gas streams.

6. Increasing Nuclear Energy Development

The use of nuclear power as a commercial energy source is expected to increase considerably in the next fifteen years. Installed capacity in 1970 was approximately 12,000 mw. This is projected to increase to 46,000 to 61,000 mw by 1975; 120,000 to 139,000 mw by 1980; and 198,000 to 286,000 mw by 1985. The variance in these estimates is in part due to delays in the licensing of the construction and operation of currently planned or completed units because of concern over their environmental effects (from waste heat disposal, normal or accidental radioactive emissions).

Most of the currently operating and planned nuclear plants utilize light water reactors. In such reactors, the heat energy created in nuclear fission is removed by the circulation of water through the fuel core to generate steam to turn turbine generators to produce electricity.

Four high-temperature, gas-cooled reactors are also completed or on order. These utilize helium circulating through the fuel core to boil water for steam to turn the turbine generators. These reactors are all of the burner type which utilize less than 2 percent of the available energy from the uranium which they burn. Breeder types of reactors, which produce more nuclear fuel than they consume, such as the liquid metal fast breeder are not expected to be available for commercial use until the mid 1980's. Breeder reactors could utilize more from 60 percent of the total energy from uranium. Thermo-nuclear fusion reactors are not expected to be a commercial reality much before year 2000.

If nuclear power were to displace all projected increases in petroleum demand (as estimated earlier, table III-4) by utilities between 1980 and 1985, it would displace demand for approximately 320,000 BPD of oil. Additional substitutions could only be made by replacing facilities in place before 1980, either before or at the end of their economic life. Some shift in remaining fossil fuel plants from base to peak loading might also be necessary. Depending on the assumptions made about the amount of residential/commercial on-site space heating capacity displaced, the additional capacity required could be between 37,000 to 50,000 Mw.[1/] The capacity which would be displaced would be located primarily in the Northeast and Great Lakes States.

If all of the oil production from oil shale would be used to provide fuel for additional oil fired power plants and on-site space heating facilities, from 37 to 50 additional muclear plants of 1000 megawatts capacity each would have to be constructed to provide a complete substitute for shale oil.

1/ Calculated on the basis of the following assumptions:

1 bbl shale oil = 5,800,000 Btu,
3412 Btu = 1 kwhr thermal,
thermal efficiency of fossil-fuel steam-generating plants 40%
thermal efficiency of onsite space heating facilities 65%, and
nuclear plants replace fossil-fuel plants operated at 75% load factor.

Since the planning, licensing, and construction lead time for nuclear power plants involves a minimum of six to eight years, nuclear power cannot be considered as an alternative to shale oil before 1980.

However, it is possible that the 37 to 50 additional nuclear plants required could be constructed by 1985, and serve as a substitute for shale oil at that time. This would represent an acceleration of 13 to 17 percent over the maximum projected capacity of 286,000 mw by 1985. To the extent that shale oil would not go into power plant or space heating uses, nuclear power would be only a partial substitute for such oil with a comparable reduction in the number of plants involved in such a substitution.

This analysis assumes that nuclear power could be a complete substitute. For less than complete substitutions, a roughly proportional reduction in the environmental impact would occur. Since specific impacts depend upon where the particular activities constituting the nuclear fuel cycle would be located, a description of specific impacts by location is not possible in most cases. The impacts described are considered to be a quantitative addition to similar impacts of existing or planned nuclear facilities.

Because of the lead times involved, nuclear power plants substituting for shale oil could only utilize current technology. Hence, the plants considered as replacements will be light-water reactors, either boiling water or pressurized water reactors. It is possible that some incremental reactors could be high-temperature, gas-cooled reactors,

which have a higher thermal efficiency and subsequently less waste heat problems. However, the number of these which could be built is considered to be small enough to be disregarded in the overall analysis. Neither breeder nor fusion reactors are considered to be viable alternatives before 1985.

In the subsequent text, the significant impacts of uranium mining and milling, power plant operation and construction, transportation of spent fuel and waste materials, reprocessing plants, and radioactive waste material storage are discussed.

a. Uranium Mining and Milling

The construction and operation of additional nuclear generating plants would require additional mining and milling of uranium ore to supply the fuel elements for these plants. An incremental operating capacity of 37,000 Mw by 1985 would require 21,000 tons of U_3O_8 for the first core fuels and 6,500 tons of U_3O_8 for annual reloads without plutonium recycling and 4,000 tons of U_3O_8 with plutonium recycling. As an average ore grade of 0.20 percent U_3O_8, a total ore output of 11 million tons would be required to supply the uranium for the first core fuels, and an annual output of 2.25 to 3.25 million tons would be required for reloads. Since the average ore grade can be expected to decline during the life of the plants, the estimated annual ore tonnage for reloads would increase, particularly after 1990.

Uranium mining and milling in the United States is concentrated in New Mexico, Wyoming, the Colorado Plateau, and south Texas. As most of

the known and potential reserves are concentrated in New Mexico, Wyoming, and the Colorado Plateau, the incremental mining and milling activity would be expected to occur there. In 1970, 53 percent of production came from underground mines, with most of the remainder coming from open-pit mines. The ratio of production between underground and open-pit mines is expected to be basically maintained over the next several decades.

In underground mining through the 1950's, excessive exposure to radioactive radon daughter products[1/] resulted in a high incidence of lung cancer. However, the annual recommended annual exposure limits have been vastly reduced in the past decade. By maintaining these lower limits the incidence of lung cancer in underground uranium miners is expected to be reduced to a level not significantly higher than that of the population as a whole.

Uranium mining is largely concentrated in relatively isolated areas distant from large population centers and urban areas. Nonetheless, it does have an adverse aesthetic impact in the areas in which it occurs, from the removal of the vegetative cover, the creation of overburden and waste rock, and the like. Open-pit mines require considerable acreage, reducing (depending upon location) the suitability of that area for other land uses such as grazing, wildlife, and some outdoor types of recreation. For underground mining, the extraction of deeper ores will tend to require some accumulation of waste rock dump areas. Planning for sequential land uses, followed by the reclamation of mined land and the backfilling of mined-out stopes with waste

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1/ Radon is a radioactive gas produced by spontaneous decay of uranium. The gas disintegrates spontaneously into socalled daughter products. In the process of spontaneous disintegration, highly radioactive emissions occur.

rock could, however, substantially reduce these land use problems.

Because of the low concentration of U_3O_8 in uranium ore, milling the ore produces considerable amounts of tailings. The milling operation for U_3O_8 required for 37,000 mw of capacity over a 25-year operating life is expected to generate around 75 to 100 million tons of tailings. These tailings contain radioactive products and, therefore, must be contained in well-constructed tailings dams to prevent erosion and leaching, which could result in the radioactive products entering surface and ground water systems. The specific adverse effects of these on the overall health of biota are not fully known; current evidence, however, does indicate increasing concentrations through upward stages of food chains. Adequate methods do exist and are being used to prevent erosion and leaching and to retain harmful mill effluents at present levels of production.

Because of their low-level radioactivity, mill tailings are unsuitable for subsequent use as fill material where human exposure might result. They are also a hostile environment for nearly all biota. Aboveground storage which minimizes erosion requires that they be covered with gravel or dirt upon which a vegetative cover can be established. Aboveground storage does, however, require considerable land area, which displaces other potential uses. Subsequently, in the future an increasing amount of tailing may be utilized to back fill mined-out stopes and open pits.

b. Powerplant Construction and Operation

Assuming an average of three 1,000 mw units per site, the construction of 37,000 mw of additional nuclear capacity by 1985 would require 13 additional plant sites (less if some units were added to existing plants). Under current siting criteria, these would be located at some distance from population centers. Assuming 500 acres per site

(based upon an exclusion area of one-half mile radius around each plant), 13 new plants would require a total of 6,500 acres, an area from which most other uses would be excluded.

Depending on the capacity of the transmission lines which would be required if nuclear energy were to substitute for the production from oil shale development, the transmission line right-of-way would require the use of ten to fifteen acres per mile of line. Certain types of development such as residences would be reached although such land would still be largely available for other purposes such as recreation. These additional transmission lines would have an adverse aesthetic impact by disrupting some scenic vistas.

Construction of the plants would present some short-run environmental problems such as the erosion of excavated materials. Special measures could be taken to prevent erosion of excavated material with subsequent siltation .

Operations of the nuclear plants will generate considerable amounts of waste heat. For example, light water reactors have comparatively lower thermal efficiencies than new fossil-fueled plants (around 33 percent compared to 40 percent). Given this difference in efficiency and under the assumption that fossil fuel plants, on average, release around 15[1/] percent of their waste heat directly into the atmosphere, a light water reactor would release approximately 50 percent[2/] more waste heat into its cooling water than a fossil fuel plant of similar size. The effects of this waste heat will depend upon the cooling method used and the location of the plant.

1/ Energy Research Needs, Oct. 1971, Section IX, Resources for the Future, p. 19.
2/ Ibid, Section VI, p. 15.

Assuming a 15-20° F temperature rise, a "once through" method (direct discharge into the original source) for a 1,000 mw nuclear plant would require 270-360 billion gallons of water per year. The effects of using a "once through" method of cooling heated water depend impart on the size of the body of water into which this heated water is discharged. The effects along ocean sites, the Great Lakes, and very large rivers are likely to be modest as the heat is more readily dispersed and more easily avoidable by aquatic species. Along smaller lakes and rivers or in bays with limited circulation, higher water temperatures can produce fish kills, interfere with fish reproduction, disrupt food chains, decrease dissolved oxygen content, drive out desirable aquatic species, and encourage the growth of undesirable algae which may speed up eutrophication within the limits of the affected area. However, sometimes the heat can be used for agriculture and other beneficial uses.

The use of wet cooling towers, removing the heat by evaporation into the atmosphere, would not pose the problems of adverse thermal effects. However, water vapor from the cooling operations could have substantial effects on local haze, fog, cloud, and ice formation. Chemicals released in the cooled water or evaporated plume could also have adverse effects on downstream and downwind biota.

The use of cooling ponds would produce less evaporation than wet cooling towers, but haze, fog, cloud, and ice formation would still occur during periods of sub-freezing temperatures. The ponds require additional acreage (an estimated 1000-2000 acres per 1000 mw unit). These may have recreational uses, but they would also displace previous land uses.

Nuclear powerplants, unlike fossil fuel plants, do not emit the usual products of combustion such as particulates, sulfur oxides, and NO_x. Hence, they do not generate the air pollution problems stemming from or require control measures for such emissions. However, they do produce radioactive emissions whose release must be strictly limited if adverse effects to the health of humans and other biota are to be avoided.

In the normal operation of the incremental nuclear generating units, there would be very small amounts of radionuclides discharged in the cooling water and gaseous plant effluents. But, assuming that present standards will be maintained and enforced (these limit the release of radioactivity to no more than would expose an individual at the plant boundary to 1 percent of the individual maximum allowed), the effects of the amounts released are likely to be negligible, as the average additional annual dose which the affected population would receive would be three to four orders of magnitude less than the average level of natural radiation exposure.

The operation of nuclear plants poses some risk of accidents. Nuclear plants are designed to minimize accidents or their adverse effects if one does occur, utilizing a "defense-in-depth" principle. This includes designing and constructing plants in such a way that accidents are prevented, designing and constructing plants to contain the effects of accidents which do occur, and siting reactors away from areas of high population density. Plants are designed to withstand a design basis accident (DBA), defined as the worst malfunction considered to have a probability of occurrence high enough to warrant corrective action. For light water reactors, the worst DBA considered is usually a major rupture in the cooling system. The maximum radiation dose which

could be received at the site boundary if such an accident occurred is estimated for some plants to not exceed the annual dose obtained from natural radioactivity.

However, the ability of emergency core cooling and back up systems to operate as planned if all systems failedis disputed. Thus, the operation of many nuclear plants over an extended period of time can be considered to pose some risk of a catastrophic accident with a very remote probability of occurrence.

c. Transportation

The nuclear fuel cycle requires the transportation of radioactive materials by truck or rail at many stages. The transportation of spent fuel elements from reactors to reprocessing plants and of high-level wastes from reprocessing plants to storage sites poses a potential hazard of considerable magnitude. Existing transportation regulations and cask designs have been developed to ensure that even if accidents in transporting these materials do occur, no radioactivity will be released into the environment. For the transport of the spent fuels and high-level wastes associated with an incremental 37,500 mw capacity, a very small number of accidents can be expected to occur during a 25-year operating life.

d. Fuel Reprocessing and High-Level Waste Storage

Spent fuel assemblies from reactors are first partially cooled at the plant site and then transported to fuel reprocessing plants where usable nuclear fuel materials are recovered from them and radioactive wastes are separated. If 37,000 mw of additional capacity would be

built, this would require either the construction of one new reprocessing plants or the expansion of existing plants. The former alternative would require new sites, entailing a complete displacement of present land uses.

While radioactive emissions during reprocessing are greater than those occurring during normal power generation the estimated dose to the affected population is still two orders of magnitude below natural levels. Hence, the impact of these emissions is not expected to be significant, even though the chronic effects of such low level radioactivity are not yet wholly known.

The high-level radioactive wastes remaining after reprocessing are first concentrated and stored in solution for five years, then evaporated to solids, sealed in containers, and put into long-term storage. The 37,000 mw of incremental capacity would produce around 300,000 to 400,000 gallons of high-level waste per year, demanding a cumulative storage capacity of 1.5 to 2 million gallons. This liquid waste, when evaporated, would yield around 3,000 to 4,000 cubic feet/year in solid waste materials for each year of operation.

Because of their high concentrations of radioactive nuclides with very slow rates of decay, these waste materials must be totally isolated from the biosphere for hundreds or thousands of years if serious adverse effects to all living organisms are to be totally avoided. The concept of storage in salt beds has been termed satisfactory by a National Academy of Science Advisory Committee. Pilot studies have been conducted for several years and are continuing to determine the acceptability of specific sites. In the meantime, wastes will continue to be stored in below surface man-made engineered storage facilities.

7. Tar Sands

If acceptable technology can be developed to permit economic oil recovery from tar sand deposits, the estimated bitumen in place in the five largest tar sand deposits in Utah of 17.7-27.6 billion barrels, which constitutes most of the known resource in the United States, could conceivably support an industry capable of producing up to a half million barrels per day for nearly 50 years. It appears unlikely, however, that development of the needed technology and of the required industry can be accomplished in time to permit significant production from tar sands before 1985. Moreover, if the same recovery method were used, there would be little difference in both degree and kind of environmental impacts caused by either oil shale or tar sand industry developments. Thus, oil production from tar sands is not considered to be a likely alternative source for the 1 million BPD capacity anticipated from the Proposed Prototype Leasing Program for oil shale.

a. Tar Sand Resource Potential

Tar sands, also called oil-impregnated rock, bituminous sandstone, bituminous limestone, etc., is distinguished from more conventional oil and gas reservoirs by the high viscosity of the included hydrocarbons. These hydrocarbons are generally semisolid to solid and not recoverable through a well by ordinary oil production methods. To initiate or sustain production, therefore, will require the continuous addition of energy

to the reservoir in some form, such as heat, fluid pressure, mechanical work by mining, or other.

Tar sand deposits in the United States are numerous and some individual deposits are extensive. The most intensive effort that has been made to evaluate the oil resource potential of tar sands in the United States (78) reports 546 known occurrences in 22 states, but because of the lack of definitive information, gives partial resource estimates for only 7 states. The estimated recoverable reserves in surface and near-surface petroleum-impregnated rocks amounted to between 2.5 and 5.5 billion barrels. Later refinements to data have been made in some areas which indicate that the total oil in place in the known deposits may be between 18.7 and 28.9 billion barrels. Most of this resource occurs in five deposits, located in the State of Utah (79). Until other deposits of size comparable to the large deposits in Utah are delineated, the present estimated volume of oil in known tar sand deposits constitutes the available resource in the United States; this is less than 30 billion barrels.

The largest known tar sand deposit in the world is at Athabasca in Alberta, Canada. This deposit has been variously estimated to contain as little as 85 billion barrels of recoverable oil by mining and surface extraction (80) to appreciably more than twice this amount by the Alberta Oil and Conservation Board. The National Petroleum Council (81) estimated that 174 billion barrels may be economically recoverable. By any estimate, the Athabasca resource in Canada is from 40 to 100 times larger than that in the United States.

A strip mining and surface extraction technology for the production of oil from tar sands has been developed to permit commercial exploitation of the huge Athabasca deposit in Alberta, Canada. Increasing production from this deposit can be expected over the next few years as other projects are approved and activated there. This technology will have but limited use, however, for the exploitation of tar sand deposits in the U.S. because none of these deposits can compare in areal size, in volume of resource, nor in thickness of overburden which have favored the large-scale strip mining operation at Athabasca. The exploitation of U.S. tar sands will probably require in situ methods for which the technology is now lacking. The lead time that will be required to develop this technology and thereafter to develop a large tar sand industry will probably prevent any significant oil production from U.S. tar sands until after 1985. Accordingly, production of oil from tar sands is not a viable alternative to shale oil in this time frame.

b. Potential Environmental Impacts

If the same recovery methods were used, there would be little difference, either in degree or in kind, in the impact produced on the environment by exploitation of oil shale and tar sand deposits. The most severe environmental impact would result where strip mining is used, because of the immense tonnages of overburden and resource rock that must be moved and the large surface areas, almost total land area, that would be disturbed. At Athabasca it is indicated that about 3.3

tons of tar sand and overburden will have to be processed for each barrel of oil produced, on a unit basis, the ratio is about 2.4 tons of sand and 1.0 ton of overburden per barrel of oil produced, depending on the bitumen content of the sand processed.

By comparison, in situ recovery methods would not cause the severe disturbance of the surface as in strip mining but would have similar impact on the environment in other respects. Regardless of the process used, the production of oil from tar sand deposits could produce hydrocarbons and other pollutants which would have to be removed to protect air quality. Air quality could also be affected by dust generated from strip mining operations, from wind-blown solids from disposal areas, or from traffic on access and service roads required by the field operations. Water quality of underground supplies and surface drainage would be subject to pollution from water produced in conjunction with the operations or from surface run-off and water leaching of dump and disposal areas.

Land used for strip mining would be totally unavailable for other uses until the land had been restored. Even in situ methods, which require comparatively little land areas for well locations and surface production facilities, would have important effects on other possible land uses, such as human habitation, recreation, livestock grazing, agriculture, or wildlife habitat, until oil production was completed. Other impacts would be associated with noise normally found with operation of process plants and equipment and with population increases in areas of established plants due to the increase in labor demands.

8. Geothermal Energy

The earth has a vast amount of internally generated and stored heat that must be considered an energy resource. However, the economics of geothermal power production are not certain, but estimates indicate geothermal power would be strongly competitive with conventional sources. Proven geothermal resources susceptible of commercial development in the U.S. are limited to one area, the Geysers, California, where potential development of 1,000 Mw of electrical generation is reasonably assured, and perhaps a total 2,000 Mw may be developed ultimately. Currently 192 Mw capacity is in operation at the Geysers producing some 508 million BTU annually. In comparison, the projected shale oil production of 1,000,000 barrels per day is equivalent to 2,120 billion BTU annually or about 5,000 times as great. Thus, geothermal power is not a viable alternate to a significant amount of shale oil production.

Geothermal energy must be used or converted to other forms of energy at the production site, because heat loss from steam or water lines becomes prohibitive at distances greater than about 1 mile from the well head. Present commercial-scale utilization of the resource in the U.S. is limited to steam-electric power production. Areal distribution of the resource leads to development of separate power plants on the order of 100 Mw capacity served by about 10 producing wells each with a well spacing of 1 well per 12 to 40 acres. This dictates small power plants connected to wells within about 1 mile by steam lines, and a series of small power plants on about 1 to 2 mile centers connected by high-voltage transmission lines. In the Geysers development, the power

company, Pacific Gas and Electric Company, has settled on two 55 Mw turbine generating units housed in a single plant as the optimum scale for this type of development (82).

In view of the technical and economic constraints, it is unlikely that geothermal energy will constitute a major supply of energy to meet the national energy demand in the period 1970-85. Under favorable conditions, geothermal energy may be locally important to several areas of the Western States. However, it probably will be insignificant as a factor in national power capacity (less than 1 percent of total) through the year 2000 (83).

a. Potential Environmental Impacts

Field development in a large field can continue for many years as new wells and additional power-generating units are developed. Since most environmental impacts can be cumulative, for example, water and air pollution, proper care must be exercised at each step. Well-site cleanup thus should be progressive, access roads should be maintained, pipelines connecting producing wells to the power plant feed lines should be regularly inspected to detect leakage, and well heads should be inspected for exterior corrosion damage or structural weakness to avert blowouts or leakage.

Most of the potential adverse environmental effects that would be present during the development phases would be magnified during full-scale operations. The potential for environmental damage increases with the addition of each new well. Some adverse environmental effects

are unavoidable, such as the potential for air and water pollution as a result of accidental releases; removal of wildlife habitat; restriction on surface use of land in the vicinity of installation; and general aesthetic deterioration through industrial development.

The principal objection to geothermal power development stems from the intrusion of industrial development into new areas. Nearby residents and outdoorsmen generally find the noise, odor, and disturbance of terrain and vistas highly objectionable.

Test drilling and production testing of geothermal steam resources would affect fish and wildlife. Most impacts would occur on or adjacent to well sites, although the impact on water quality could be more than localized. The magnitude of particular impacts would be interrelated with fish and wildlife and their habitat within the area of development influences, extent and duration of the entire geothermal development activities and operations, and the effectiveness of control measures.

Blowouts, in which steam or water escapes uncontrolled, potentially pose a distinct environmental hazard in geothermal drilling. The principal adverse environmental effects of such accidental releases are safety of operating personnel, waste of the resource, noise nuisance and air contamination from gaseous emissions (hydrogen sulfide and others). Condensed, the gaseous emissions could enter and adversely affect ground water. Once a blowout occurs it is troublesome to control because of the difficulty in handling escaping hot fluid. However, unlike similar problems encountered in petroleum drilling, there is essentially no fire hazard in the case of a geothermal accident. To further minimize this

hazard, proper casing design is required to assure that the pressurized fluid will be confined to the well bore and can be controlled through surface shut-in equipment.

If a fresh-water aquifer occurs above a geothermal reservoir which contains hot saline water, tapping the geothermal strata could result in contamination of the fresh water if one horizon were not kept isolated from the other by properly cementing the casing of either production or reinjection wells.

Experience in petroleum production indicates that marked changes in reservoir pressure, whether due to pressure reduction from the production of fluids, or to pressure increase due to injection, may in certain types of reservoirs, especially in faulted or fractured rocks, result in instability leading to earthquakes. Such instability due to production alone has been documented in the Wilmington Oil Field, California (84). Instability due to injection was documented at the Baldwin Hills Oil Field, California (85), and at the Rangely Oil Field, Colorado (86), and in connection with injection of waste waters at the Rocky Mountain Arsenal, Colorado (87). Similar increases in seismic activity have also been noted in association with filling of large surface reservoirs with attendant change in hydrostatic head, including Lake Mead on the Colorado River and Lake Kariba in Africa (88). The role of fluid-pressure changes in triggering seismic activity is not well-known, but a causative relation has been

established in many areas. In general, such activity has not proven disastrous, but the potential for a major quake cannot be ruled out. In any event, seismic activity must be counted as a potential environmental impact associated with geothermal development, and provisions must be made for seismic monitoring before and during major production. If monitoring indicates a significant increase in seismicity, particularly in intensity of motion, removal steps to alleviate stress would have to be initiated promptly.

Subsidence of the ground surface over and around a geothermal reservoir can result from the withdrawal of large volumes of fluids (84, 89). Subsidence would reach a maximum rate during full-scale operations unless fluid is returned to the reservoir.

Electrical transmission lines are generally benign and some favorable environmental impacts could be attributed to improved fire protection resulting from clearing of the rights-of-way. The principal adverse impacts are aesthetic due to the intrusion of the structures on vistas. Disturbance of the terrain is minimal except for clearing trees and brush. However, some unresolved questions exist concerning the effects on wildlife migration and surface erosion.

Geothermal waste fluids normally contain sufficient mineral matter that discharging them into streams and lakes would be generally unacceptable. Even discharge to the ocean might be unacceptable in view of the thermal load. Disposal to otherwise useable underground

waters likewise would generally be unacceptable. The solution available in most situations is reinjection of waste fluids into the producing zone. This has the double advantage of providing recharge and pressure maintenance to the geothermal reservoir, as well as providing for waste disposal. It might be possible to evaporate wastes and recover minerals and salts of economic value.

Another aspect of waste disposal not generally considered is that of gaseous wastes. Steam from cooling towers in some situations could bring on fogging problems. Likewise release of noxious gases with such steam also constitutes an adverse impact, but certain gases, particularly hydrogen sulfide and ammonia, can be removed from power plant steam before release.

9. Hydroelectric Power

The potential of hydroelectric capacity is limited. Of the 100,000 Mw of potential capacity yet to be developed in the Lower 48 States approximately 30,000 Mw is likely to be developed by 1990 under existing programs. To equal the energy available from shale oil would require commissioning an additional 37,000 to 50,000 Mw of the remaining potential, assuming that the remaining potential capacity is based on average streamflow conditions and that shale oil is assumed to be completely utilized for electric energy production. That assumption is only valid for purposes of this study. The potential

sites would most likely be developed to provide area load peaking capacity requirements in conjunction with fossil or synthetic fuel or nuclear base load plants. The development of additional dam sites with hydroelectric capacity could face opposition and delay on environmental grounds. However, recognition must be given to the fact that siting of fuel burning plants also would face environmental opposition.

The generating potential of any hydroelectric site is a function of both steam discharge and the height of fall. The better hydroelectric sites are concentrated in areas with heavy precipitation and large topographic relief. The following table shows the extent of U.S. potential and developed water-power capacity as of January 1971 obtained informally from the Federal Power Commission:

Geographic Region	Potential Power (10^3 Mw)**	Percent of Total	Developed Capacity (10^3 Mw)	Percent Developed
New England	4.8	2.7	1.5	31.3
Middle Atlantic	8.7	4.8	4.2	48.3
East North Central	2.5	1.4	0.9	36.0
West North Central	7.1	3.9	2.7	38.0
South Atlantic	14.8	8.2	5.3	35.8
East South Central	9.0	5.0	5.2	57.8
West South Central	5.2	2.9	1.9	36.5
Mountain	32.9	18.3	6.2	18.8
Pacific	62.2	34.6	23.9	38.4
Alaska	32.6	18.1	0.1	0.3
Hawaii	0.1	0.1	-	-
Total	179.9	100.0	51.9	28.8

Of the potential hydroelectric capacity of 179,900 Mw in the U.S., 28.8 percent or 51,900 Mw has been developed leaving approximately 130,000 Mw to be developed. Of this 130,000 Mw of capacity some 32,600 Mw is located in Alaska. Sparsity of population and remoteness from population centers make the economic feasibility of large hydroelectric projects in Alaska subject to considerable doubt. Of the approximately 100,000 Mw of capacity yet to be developed in the lower 48 States 65,000 Mw are concentrated in the Mountain and Pacific regions. About 35,000 Mw of capacity potential could be developed in the remainder of the United States.

The Federal Power Commission projects electric generating capacity in the U.S. as follows:

Year	Total Generating Capacity (Mw)	Total Hydro Capacity (Mw)	Hydro as Percent of Total
1970	340,058	51,641	15.2
1980	665,000	68,000	10.2
1990	1,260,000	82,000	6.5

** Mw = Megawatts

Thus, by 1990 development of approximately half of the Nation's total hydropower potential will comprise only 6.5 percent of total electric generating capacity.

It should be noted that few dams are built solely for hydroelectric power generation. Irrigation, navigation, municipal, and industrial uses, as well as flood control are important, and frequently are the dominant uses.

a. Potential Environmental Impacts

Numerous environmental impact statements filed by the Bureau of Reclamation of the Department of the Interior and by the Corps of Engineers describe environmental impacts of specific hydroelectric projects.

Hydroelectric power produces no air pollution, radioactivity, waste, heat nor water pollution (with the exception of the loss of oxygen content in storage facilities). Impacts on land and water resources tend to be limited to the vicinity of the power generation site. Dams valuable for hydroelectric purposes may be otherwise useful for such needs as irrigation and flood control. Lakes behind dams created for hydroelectric purposes provide recreational opportunities such as swimming, fishing, and boating.

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and lake (agriculture, minerals, wildlife habitat, free-flowing river recreation, historical and archaeological resources, timber areas, and others).

Alteration of river flows may lead to silting behind the dam, thus progressively reducing reservoir capacity and its effective use, and finally, after many years, filling of the lake. Alteration of downstream flows from powerplant discharges can cause scouring of river banks and bottoms.

Fish and wildlife habitat may be adversely altered. The reproductive habits of anadromous fish may be severely altered by dam construction, unless elaborate provision is made for fish ladders or other means to provide safe fish passage.

b. Special Problems - Alaska Hydroelectric

A specific disadvantage of the potential Alaska hydroelectric alternative would be the necessity of constructing transmission lines to carry power from Alaska not required in that area to the lower United States. This would be a distance of 1500 to 2000 miles from Alaska hydroelectric sites to the Northwest-Canadian U.S. border. Such distances would preclude the use of alternating current lines because of technical economic infeasibility. The use of direct current lines assumes adequate technical research developments by the time such lines would be needed. Approximately 20 D.C. lines with a 1,000-kv rating would be required to transmit approximately 30,000 Mw from Alaska to the contiguous U.S. This further assumes that all potential hydroelectric sites in Alaska would be developed and that the power requirements of that State would not be great enough to utilize all of this hydroelectric capacity.

10. Other Energy Sources

There are other potential energy sources which need to be recognized as possible energy alternatives to oil-shale development. At present, these alternatives are not considered viable due to a lack of proven technology for production scale application, nonsubstitutability, cost, and timing of development. These include improved fuel use efficiency, tidal power, solar energy, biological conversion of wastes to oil, and the use of liquid hydrogen as a motor fuel.

Potential environmental impacts of these alternatives are difficult to assess, particularly where there is a great amount of research and development that must be done before operational scale systems can be developed, tested, evaluated, and readied for production application. It is not believed that any significant energy production can be obtained from these systems within the relevant time frame. Essentially, these are all in the research and development stage, and, while some discussion of potential environmental impacts is included, it is not possible to develop a full discussion due to the lack of necessary data. The following sections briefly describe the current and short-range status of each of these potential alternatives.

a. Magnetohydrodynamics

Magnetohydrodynamics (MHD) power generation is a technique for electrical generation which passes a hot ionized gas, or liquid metal, through a magnetic field. Such a high temperature, one-stage conversion device has the potential of high overall efficiencies. Though the concept of

MHD generation has been known for over 100 years, it is only during the past decade that significant technological advances have produced systems which offer promise for use in the electric power field. Three basic approaches to MHD generation are being explored--open-cycle, closed-cycle, and liquid metal systems.

The MHD open-cycle generation, used as a "topping unit" in conjunction with steam-turbine generation, appears to hold the most promise for MHD central-station power generation in the near future. Overall system efficiency is expected to increase to a range of 50 to 60 percent, which could provide a fuel saving of 20 to 30 percent over fossil fuel steam-electric plants. General application of coal-fired MHD topping units by the mid-1980's could effectively extend fossil fuel reserves and enhance the potential for use of coal for power generation. Since the MHD generator would require little cooling water, the combined MHD-steam units would require considerably less cooling water per megawatt of capacity than conventional fossil fueled or nuclear steam-electric units.

Before MHD can be utilized for central power station generation, there are many significant technological problems which must be solved. No economically practical system has yet been demonstrated for burning coal or coal-derived fuels. Designs to date have been small scale with short lifetimes and lower efficiencies than would be required for utility operation. There are problems of developing high-temperature electrodes, super-conductivity magnets, seed-recovery systems, high-temperature metal erosion and corrosion, etc. The high temperatures and gas passage time

are conducive to fixation of nitrogen so there may be significant NO_x air quality problems.

MHD research presently is being conducted in England, France, Germany, Japan, Poland, the Soviet Union, and the United States. The Soviet Union appears to have made a strong commitment to the development of MHD for commercial use. Soviet engineers express confidence that an open-cycle MHD unit of appreciable power output will be operating in the 1970's, but there is yet no evidence of proven economic feasibility. A 75-Mw combination MHD steam pilot plant (25 Mw MHD and 50 Mw steam) is being constructed near Moscow. For the present, only a 25-Mw portion of the plant currently is planned for completion and operation. Japan also has made great strides in achieving the high field super-conductivity magnets necessary for MHD.

Utility companies, manufacturers, research institutions, and the U.S. Government have been actively involved in MHD investigations since the 1950's. A 1969 Office of Science and Technology report identified many problem areas in which research and development are needed before MHD power system work can proceed to full-scale prototype. This report recommended that the U.S. Government encourage work on solving the difficult problems of coal-burning open-system MHD systems, and several related research projects and studies now are in progress.

While MHD appears to offer considerable future potential for coal-fired power generation, the technologic and economic uncertainties are still so great that it cannot be considered as a viable alternative power source by 1980. (For additional detail, see Part 1, Chapter 9 of the Federal Power Commission's 1970 National Power Survey Report, December 1971).

The increased thermal efficiency would reduce the overall amount of fossil fuel requirement per unit of energy produced, thereby reducing the related fuel source production environmental impacts by a like amount. The reduced water-cooling requirement would result in less thermal pollution impacts on water quality. The wide distribution of coal resources and reduced cooling water demand would be conducive to location of generation stations near coal resource and population centers, thereby reducing long distance electrical energy transmission requirements and dependency. Reduced fuel consumption would result in a lower volume of noxious effluents than would be discharged into the atmosphere by a comparable capacity of conventional power plants.

There is the potential of increased NO_x problems resulting from high-temperature operations. The increased coal demand would require a corresponding increase in surface or subsurface coal mining with the inherent environmental impacts of such mining. There also would be a corresponding increase in the health and safety hazards to the miners engaged in producing the additional coal volumes. While generators could be located close to coal deposits, there would be the additional environmental impacts associated with transportation from mine to generator, additional transmission lines, development and operation of power station sites, and possible noise problems.

b. Fuel Cells

Fuel cells are electrochemical devices in which the chemical energy of fuel is converted continuously and directly to low-voltage direct current electricity. The basic process is similar to that of a battery except that the fuel cell is an open system requiring a continuous supply of reactants for the production of electricity. Their potential advantages over more conventional energy conversion systems are their quietness, low temperature of operation, minimization of pollution, reliability, and greater efficiencies (up to 70 percent). Nearly one and one-half times more electrical energy can be obtained from a ton of coal in a fuel cell system than for a comparable amount burned in a modern conventional power system.

There has been considerable research and development of fuel cells in the United States and Europe. While most of the research in the United States has been aimed toward development for specialized uses in space and military applications, a number of projects also have been directed to commercial power production applications. Examples of the most probable near-term uses of fuel cells could be storage of energy during periods of off-peak demand; on-site reserve or emergency power; base-load or peaking power supplements to existing electric power systems; individual home, apartment, industrial or commercial complexes tailored to specific customer needs; and in the transportation field where batteries are now used or where electric propulsion could substitute for internal combustion engines.

Because of the current necessity for costly metal catalysts and reforming and fuel purification processes, the near future of fuel cells,

even for small power units in a mass market, is remote. General application will be feasible only when efficient units capable of using impure, low-cost fuels are developed and when long reliable life units can be constructed. Even when such technology is proven, the fuel cell is not expected to replace central power station generation.

To the extent that fuel cells could replace other forms of power generation, there would be environmental advantages such as quietness, low operating temperatures, and absence of toxic wastes. Use of fuel cells in substations could reduce the need for central station power and transmission lines. Energy resource source impacts cannot be evaluated until probable fuel sources are more adequately identified.

c. Thermoelectric

When two dissimilar metals are joined together in the form of a loop and one of the junctions is held at higher temperature, an electric current will flow. With possible efficiencies in generator technology in the order of 30 percent, it appears that overall efficiencies of thermoelectric systems could not exceed 10 to 15 percent. Short operating lifetimes, which result from the instability of thermoelectric elements at high temperatures necessary for higher power operation, and undesirable heat transfer from the hot to cold junctions, which result in low efficiencies, are major obstacles to additional progress in development of this electric energy source. Although thermoelectric generation will doubtless receive continued attention for special low power applications, it would seem to

hold little potential for central power station plans in the foreseeable future. (For additional detail, see Federal Power Commission's 1970 National Power Survey, December 1971).

d. Thermionic Generation

When a metal is heated, a point is reached where its electrons acquire enough energy to overcome retarding forces at the surface of the metal and escape--boil off. When collected on another cooler metal surface, electrical energy can be generated by joining the two pieces of metal with an external circuit. Since thermionic generators are another type of heat engine, their efficiency theoretically is limited to 35-40 percent. At present, efficiencies ranging from 5 to 25 percent have been reported for test models. Commercial exploitation of the phenomenon awaits solution of difficult materials problems related to operations above 3000° F and, in isotopic-fueled devices, radiation damage. The Federal Power Commission's 1970 National Power Survey indicates that the concensus is that future efforts in thermionic development during the next decade will be concentrated in space oriented activities. The principal effort will be directed to the development of nuclear-fueled systems to be used as power sources for interplanetary expeditions. There is little likelihood of thermionics achieving commercial realization for large-scale generation within the next several decades. Accordingly, such conversion systems do not represent an alternative energy source in the near future.

The state of development is not sufficiently advanced for an evaluation of potential environmental impacts. Since it is a type of heat

engine, the associated loss of heat is a potential source of thermal pollution. Heat sources of fossil or nuclear fuels also would have their related environmental impacts.

e. Tidal Energy

Tidal power is a hydroelectric energy source similar to other water power sources except that it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. There are two major tidal power sites in the United States which have significant potential for such development (90.) The Bay of Fundy with nine sites, including many on the Canadian side, has an average potential power capacity of approximately 29,000 Mw, and Turnagain Bay in Cook Inlet, Alaska, has an estimated potential power capacity of 9,500 Mw. The distance from population centers makes the Turnagain Bay site doubtful from an economic standpoint. If the Bay of Fundy capacity was developed with half of the production going to Canada and half to the United States, the total addition to U.S. capacity would be some 15,000 Mw. This would represent approximately 1.1 percent of generating needs by 1990.

The major technological problem associated with the development to tidal energy would be the need to develop turbines able to operate economically under low hydrostatic heads (91). Depending upon base load, substitutability, and conversion efficiency factors, such production could be equivalent to from 0.2 to 0.4 million barrels of oil per day. The overall impact of tidal power on the U.S. energy supply would be minimal that it does not represent a significant alternative to the need to develop other energy sources.

There would be significant environmental considerations associated with the damming and alternate filling and emptying of bay and estuary areas, such as impacts on sport and commercial fisheries, wildlife, water quality, recreation uses, other land uses, aesthetics, etc.

f. Wind Energy

The power in the wind is the result of a mass of air moving at speed in some particular direction. To capture such power requires placing in the path of the wind a machine which transfers the wind power to the machine. There is a wide range of estimates as to what the energy potential might be--one figure is 20 billion kw at elevations low enough for extraction by aerogenerators (wind turbines). This figure reflects an ultimate potential, but it has little bearing on the degree to which this resource can be utilized. Economical power generation requires an average annual wind velocity of about 30 mph with nearly steady magnitude and direction and topography in which boundary-layer effects are minimal.

Although there are many locations that appear suitable for aerogenerators, their use would be contingent largely on the development of low-cost generators, a site amenable to low-cost installation, a favorable overall wind speed, and an electric grid capable of profitable use of interruptible power of this nature. Were it feasibly economically possible to generate 10 billion kwh per year from wind sources, it would reduce the use of conventional fuel by an amount of 4 million tons of coal or the equivalent of other energy sources.

Wind energy does not appear to be a viable alternative to traditional large-scale energy sources at this time as a considerable amount of additional research and development is required. Even with reasonable success in such effort, favorable cost-benefit is questionable because of the high equipment costs and intermittent characteristics of the power source. However, there are those who feel that substantial electrical energy production is possible now from lower velocity winds and the use of technology developed in past research projects even though there has not been major activity toward commercial development of wind energy for several years (92).

Since the use of the wind for power generation is a pollution-free source of electrical energy that would replace the need for fossil fuel or nuclear generation, there would be an environmental benefit that would be generally in direct ratio to the adverse environmental impacts of the alternative electrical energy generation source displaced. Such environmental impacts are set forth in the corresponding sections of this report.

The primary adverse environmental effect would be the aesthetic effect of a large number of towers with heights of as much as 1,000 feet topped with large generators turned by wind turbines with blades of 50 to 200 feet in length, or possibly even larger, which would be at prominent locations. Previous large-scale efforts have failed due to structural factors, so tower structures probably would require heavy guying. There would be land surface impacts resulting from the construction and operation of numerous generator sites and access thereto. Since each tower would have to be serviced by transmission lines and related structures to connect

the wind generation grid into power grids, there could be considerable environmental disturbance associated with the development and operation of such lines.

g. Solar Energy

Solar energy is a source of both heat and electromagnetic radiation. Although the solar energy density is low, the United States land area intercepts each year about 600 times its total 1970 energy requirements. Such heat can be used for electricity generation, space heating, cooling, and processing of industrial materials. The electromagnetic properties of solar radiation produce photosynthetic conversion and storage of energy in plants and other photochemical reactions which also convert and store energy.

The number and range of potential solar applications are extensive but the present state of the art is such that energy collection efficiencies are low and the requirements for energy storage resulting from the intermittent nature of the source result in costs that are prohibitive for general use. A typical 1,000 Mw power plant operating in a 1,400 Btu/day solar climate would, with present technology, require 37 square miles of collector surface (assuming efficiency of conversion of solar energy to process heat is 30 percent and to electrical energy is 5 percent). The many square miles of collector surface that would be required for even a medium-sized power generation facility would have significant impact on the land area, its other use or resource values and on the general environment. There would be a major aesthetic intrusion in desert areas which now are generally unmarred by man's activities.

Such large collector areas and low efficiencies make it unlikely that solar energy will have any significant impact as a large-scale source of power within the next 30 or more years as the economics are very unfavorable compared to many alternatives. Even a 300 percent increase in the solar cell efficiency would not result in power costs that would be economically acceptable for general use. A massive research and development effort over an extended period of time would be required to lower costs, increase conversion efficiency and to achieve acceptable system performance.

Examples of other types of solar generation potential include floating power plants which would use the solar-produced temperature differentials which exist between the upper and lower levels of Caribbean waters and the Gulf Stream. A second concept deals with the orbiting of space vehicles for the purpose of creating central power generation. Systems such as these have not yet been developed or tested so they do not represent feasible energy source alternative that can be considered at this time.

h. Biological Energy

Organic wastes in the United States are a potential source of energy of significant magnitude. Of the annual production which is excess of 2 billion tons, some 880 million tons are organic, moisture-and-ash-free material. Animal manure is the largest single organic waste; however, other agricultural wastes and urban refuse and commercial waste add significantly to the total. Bureau of Mines research (93) has shown that it

is possible to convert such organic wastes to oil with a potential of 1.25 barrels of oil per ton of waste. If all of this waste could be converted to oil, it would represent over 1.3 billion barrels of oil a year. This compares with a 1970 petroleum demand of 5.4 billion barrels. However, it must be recognized that even if this preliminary technology could be developed to commercial feasibility, only a fraction of the organic wastes could be collected with a reasonable amount of cost and effort for application of this process. Nevertheless, its use does have the potential of providing a significant supplemental source of oil. The process lends itself to essentially pollution-free operation while at the same time offering a solution to a portion of the problem of solid waste disposal. The oil has a low sulphur content and a high heating value. If only half of the organic waste could be converted to oil, it could supply an amount equal to current volume of residual fuel oil now used for electrical generation.

Preliminary research has been done in closed, batch autoclaves. Currently, a continuous unit with a capacity of 20 pounds per hour is being operated.

Considerable additional work over a period of years will be required to move from the present early stage research to demonstration operations at a commercial scale to prove technological feasibility and to develop adequate economic data. No cost or estimate of probable commercial-scale production can be made at this time.

The process lends itself to implementation of a waste conversion process which will recycle waste to provide fuel resource values and, at the same time will greatly alleviate many of the critical solid waste disposal situations confronting the Nation. Water quality problems associated with feedlot and agricultural wastes could be mitigated. The need for land fills or other volume forms of disposal would be greatly reduced as the solid residue from the process would consist of the mineral constituents in the original charge. Its quantity would be small and because it would be sterile, it would produce no problem as land fill material. Since the process produces a low sulphur oil with high heat value, it could replace the need for natural oil production with a corresponding reduction in all of the related environmental hazards of such production.

It is doubtful if production of significant magnitude could be achieved by 1985 so, pending further research and development, it cannot be considered a viable alternative at this time.

I. Liquid Hydrogen

The use of liquid hydrogen as an alternative to fossil fuel for vehicular power systems appears to be technically feasible. Hydrogen would be separated from oxygen in water by an energy-consuming electrolytic process at a primary fixed-station energy source. The hydrogen then would be liquified, transported and distributed as fuel.

Prior to 1958, liquid hydrogen was produced only in small quantities and was primarily a laboratory curiosity. Owing to demands made by the space program, facilities were constructed in the United States to produce

more than 150 tons per day, but costs are relatively high. Cost projections for the electrolytic production of hydrogen range from a low of $0.04 per pound using electrical energy from a large breeder-type reactor to about $0.12 per pound for other energy sources. By comparison, the present cost to produce gasoline is about $0.02 per pound. In addition to the cost of production of liquid hydrogen, it also is essential to consider the cost of developing and implementing the process, storage, transportation and combustion methods. Conversion costs would be extremely large, so development of this alternative internal combustion engine fuel source could take from 20 to 50 years. Accordingly, it is not a viable alternative for consideration within the 1980 time frame. While use of hydrogen as a vehicle power source has the environment advantage of being pollution free because the combustion product is water, the energy requirements to separate hydrogen from oxygen are considerable with corresponding environmental impacts depending upon the energy source involved.

D. Combinations of Alternatives

In the interest of clarity of presentation this analysis has discussed separately each potential alternative form of energy to a million barrel per day rate of shale oil production. It is highly unlikely that there will ever be a single definitive choice to be made between any potential energy form and its alternatives. Each may have a role to play; some may make major contributions to our energy supplies, while others may be subordinated to lesser roles. Some alternatives may be developed rapidly; others may evolve more slowly--perhaps to make a more important contribution at a later date. Predictions made on the basis of present knowledge of the relative roles of these potential alternatives is a highly subjective exercise which must necessarily include a large measure of judgment as to future trends in such variables as the direction and pace of technological development, the identification of useable resources, the rate of our natural economic growth and changes in our life style.

Table 10 Summarizes the pertinent data developed in other sections of this volume as to the possible alternatives or combination of alternatives to provide the energy equivalent to that projected for oil shale development. As indicated, there are at least five alternatives which appear to be potentially feasible for equaling this energy supply from oil shale for the 1985 timeframe. These are: (1) reduced energy demand, (2) increased foreign imports, (3) increased domestic conventional oil and gas production, (4) coal gasification, and (5) replacement of liquid fuels with equivalent quantities of electricity generated by coal and/or by nuclear power. The other alternatives

OIL SHALE AND POTENTIAL ALTERNATIVES

Energy Source	Potential Incremental 1985 Production[1/] Daily (Physical Units)	Energy Equivalent (Trillion Btu)
Shale Oil	1 million barrels	5.80
Reduced Energy Demand Alternatives[2/]		5.80
Liquid Fuel Alternatives		
1. Increased Foreign Imports[3/]	1 million barrels	5.80
2. Increased Domestic Production[4/]	>1 million barrels	>5.80
Gaseous Fuel Alternatives		
1. Increased Domestic Production[4/]	>1 million barrels	>5.80
2. Nuclear Stimulation[5/]	275 billion scf	2.75
3. Coal Gasification[6/]	550 billion scf	5.50
Increased Electrical Capacity Alternatives		
1. Coal[7/]	95 million short tons	5.80
2. Nuclear[8/]	37,000 to 50,000 mw	4.30 to 5.80
Now Energy Alternatives		
1. Tar Sand Oils[9/]		
2. Geothermal Energy[10/]		
3. Hydroelectric Power[11/]		
4. Other Energy Sources[12/]		

1/ That production that may be obtained in addition to the production anticipated from the energy source
2/ See discussion beginning on page 68.
3/ See discussions, pages 44 to 49 and 79 to 90.
4/ Various combinations may contribute, but the sum is not known. Elimination of market demand prorationing will not contribute to the total (see discussion, page 91); but development of the shut-in capacity in the Naval Petroleum Reserve at Elk Hills, California could increase domestic oil production by 350,000 barrels per day (page 111). Other options include: (1) Increased offshore production (pages 33 and 99), and (2) increased onshore production (page 110), including production from Artic areas other than the Prudhoe Bay area (page 117). Economic incentives applied to domestic energy fuels will also effect the relative economics of shale oil production; the energy fuels will also effect the relative economics of shale oil production; the relationship between these competing energy forms is not now known. (page 92).
5/ See Page 125.
6/ See Page 156.
7/ See Page 133.
8/ See Page 162
9/ See Page 173
10/ See Page 177.
11/ See Page 182.
12/ Includes magnetohydrodynamics, fuel cells, thermoelectric, thermoionic, tidal energy, wind energy, solar energy, biological energy, and liquid hydrogen. See discussion, pages 187 to 201.

shown are not considered viable short-term energy replacements because of limited technology.

It seems most probable that many of the alternatives to shale oil outlined in table will be developed to some degree. Understanding of the extent to which they may replace or complement shale oil requires reference to the characteristics of our total national energy system. Factors most relevant to the issues at hand are outlined below:

1. Historical relationship indicate that energy requirements will grow at approximately the same rate as gross national product.
2. Energy requirements can be constrained to some degree through the price mechanism in a free market or by more direct constraints. Reduction in energy requirements may be accomplished through substitution of capital investment in lieu of energy; e.g., insulation to save fuel. Other potentials for lower energy use have more far-reaching impacts and may be long range in their implementation--they include rationing, altered transportation modes, and major changes in living conditions and life styles. Even severe constraints on energy use can be expected to only slow, not halt, the growth in energy requirements within the time frame of this Statement.
3. Energy needs are not monolithic. Solid fuels cannot be used directly in internal combustion engines, for example. Fuel conversion potentials are severely limited in the short term although somewhat greater flexibility exists in the longer run and generally involve choices in energy-consuming capital goods. (see Section II, Part C of this Volume).

The principal competitive interface between fuels is in electric powerplants. Moreover, the full range of flexibility in energy use is limited by environmental considerations.

4. A broad spectrum of research and development is being directed to energy conversion--more efficient nuclear reactors, coal gasification and liquefaction, liquified natural gas (LNG), and shale retorting, among others. Several of these should assume important roles in supplying future energy requirements, though their future competitive relationship is not yet predictable.

5. Major potentials for filling the gap from domestic resources are:

   - More efficient use of energy
   - Environmentally acceptable systems which will permit production and use of larger volumes of domestic coal.
   - Accelerated exploration and development of all domestic oil and gas resources.
   - Development of the Nation's oil shale resources.

   Of the foregoing, increased domestic oil and gas production offers considerable possibilities, since indicated and undiscovered domestic resources total some 417 billion barrels of oil and 2,100 trillion cu. ft. of gas which are estimated to be producible under current technology. However, the feasibility of providing adequate incentive and reducing the uncertainties inherent in petroleum exploration are not known.

6. The acceptability of oil and gas imports as an alternative is diminished by:

   - A narrowing gap between costs of foreign and domestic oil.
   - Apparent high costs of liquefying and transporting natural gas other than overland by pipeline.
   - The security risks inherent in placing reliance for essential energy supplies on sources which have demonstrated themselves to be politically unstable and prone to use interruption of petroleum supplies to exert economic and political pressure on their customers.
   - The aggravation of unfavorable international trade and payments balances which would accompany substantial increases in oil and gas imports.

Though this section considered the possibility of combinations of alternatives, in view of the foregoing it seems reasonable to postulate that for some time to come the basic alternative to the production of a million barrels of shale oil would be a million barrels of imported petroleum. (For a further discussion of this subject, see the section of this volume on the substitutability of energy forms.)

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